OPTIONS TO REDUCE CO_2 EMISSIONS FROM ELECTRICITY GENERATION IN THE APEC REGION

Energy Working Group Project EWG 04/2000

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EXECUTIVE SUMMARY

The APEC economies account for 64% of global economic activity and 42% of the world's population. Related to these factors, APEC economies collectively consume 59% of the world's energy requirements and emit 59% of the world's carbon dioxide from fossil fuel combustion. The share of the world's energy use occurring in APEC economies is likely to increase.

The U.S. Energy Information Administration (2001) forecasts electricity consumption in the APEC region will grow at a rate of about 2.8% per year over the period from 1999 to 2020. At this average growth rate, net electricity consumption in the APEC region will grow from 7,543 TWh in 1999 (APEC, 2001) to 13,470 TWh in 2020, an overall increase of 79%. To meet this demand for electricity in 1999, total electricity generation in APEC was 8,665 TWh in 1999. On an output basis, approximately 68% was produced using fossil fuels, followed next by nuclear energy at 16%, hydropower at 15%, and other energy sources at less than 1%. The projected growth in electricity consumption combined with the currently high reliance on fossil energy for electricity generation (43% coal) in the APEC region makes this sector a significant current and growing contributor to emissions of greenhouse gases and air pollutants.

Fossil fuel combustion for power generation in APEC economies generates approximately 42% of the total CO_2 emissions from fuel combustion in the APEC region, and 24.5% of the CO_2 emissions from fuel combustion in the world. Associated with the CO_2 emissions are substantial emissions of common and toxic air contaminants, which result in impacts to human health and the environment.

This study was undertaken to help APEC member economies address greenhouse gas emissions and environmental issues associated with use of fossil energy to generate electricity. The study furthers APEC's objectives by expanding the information available on methods for improving the efficiency of current technologies and on the performance of alternative and emerging technologies. The study focuses on the electricity generation sector in the APEC region. The principal goals of the study were: 1) to review current and emerging options to improve efficiency and reduce CO_2 emissions from burning fossil fuels to generate electricity; 2) to develop data on the status of current CO_2 emissions and CO_2 emission reduction measures from the electricity generation sector; and 3) to determine the current effects of emissions from combustion of fossil fuels for electricity generation on air quality and health and the possible effects of CO_2 reduction options on air quality. The study identifies technical options available to reduce CO_2 emissions from existing and planned power plants for the APEC region, and, at a screening level of detail, identifies the more promising CO_2 emission reduction options.

Reductions in CO_2 emissions from power plants can be achieved directly by increasing plant efficiency, using lower carbon fuels, or capturing and sequestering CO_2. Improvement in the efficiency of electricity generation from fossil fuels can be achieved by implementing a range of changes to optimize existing power plants, or by either repowering existing plants or building new plants using advanced high-efficiency and cogeneration technologies. A review of these technologies was completed to document the efficiency gains possible for coal, gas and oil fired power plants by improvements to combustion, steam cycle design, and operating and maintenance practices, as well as by repowering using a range of proven and emerging clean fossil energy technologies. CO_2 reduction from firing with lower-carbon fuels and biomass fuels were estimated based on changes in the carbon content of the fuel and accepted methods for characterizing emissions from biomass fuels. An overview of CO_2 capture and sequestration technology was completed to determine its development status and to characterize performance, efficiency and cost impacts for power plants. Further development of this technology will be needed to reduce its cost and the adverse effect on energy efficiency.

In order to assess the CO_2 emission reduction potential for the APEC electricity generation sector, the CO_2 reduction options identified from the review of the available technologies were integrated into various hypothetical scenarios for application to existing plants. Nineteen scenarios were selected to illustrate options of potential interest to both developed and developing economies, current and future facilities and for near term or longer term application. The identified scenarios can be grouped into the following four basic categories, and are listed individually in Table S-1:

- Combustion, steam cycle, and operating and maintenance (O&M) upgrades;
- Co-firing and switching to lower carbon fuels;
- Repowering using more efficient technology, or biomass fuels; and
- Combined heat and power (CHP) generation.

Estimates of CO_2 emission reductions potentially achievable in the APEC region were developed for 1998 using data from the Utility Data Institute worldwide power plant database on the capacity and the type of energy technology used at operating plants. The reduction in CO_2 emissions from application of each of the identified scenarios was determined based on the estimated improvement in plant efficiency, or the reduction in CO_2 emission intensity, data on the existing generating capacity of each energy technology, and an assumed application level for the scenario in the APEC region (Table S-1). The predicted CO_2 emission reductions for each scenario, if applied at the assumed percentage of existing generating capacity in the APEC region, are summarized in Figure S-1.

Five combustion, steam cycle, and O&M improvement scenarios were identified and evaluated, and are labelled E1 to E5. The most promising is Scenario E4, which addresses improvements to power plants fired using pulverized coal. The estimated CO_2 emission reduction in the APEC region for this scenario is 165 Mt. Scenario E1 for gas and oil subcritical steam plants is also an attractive option in that it shows a potential reduction of 26 Mt of CO_2, and could be accomplished less expensively than upgrading PC power plants. Because of the relatively low CO_2 reduction estimates, scenarios E2, E3, and E5 are less attractive for achieving CO_2 emission reductions.

Three 25% natural gas co-firing scenarios (E6-E8) were investigated, of which Scenario E7 that co-fires gas in pulverized coal subcritical plants is the most attractive. It is estimated that 19 Mt of CO_2 could be reduced in APEC economies by co-firing gas at 25% of fuel input at 189 plants in 1998, assuming circumstances permit firing the additional quantity of natural gas economically. As these plants are indicated to presently have gas-firing capability, the capital cost should be low. Operating cost would increase due to the fuel cost differential, which would need to be examined on a site-specific basis. Switching to 100% natural gas from pulverized coal in Scenario E10 is the most attractive, with an estimated CO_2 emission reduction of 77 Mt of CO_2. Co-firing 50% gas would produce a 39 Mt CO_2 reduction. Switching to oil is considered in Scenario E11.

Repowering scenarios are labelled E12 to E19. Estimated reductions in CO_2 emissions for these scenarios range from 13 Mt to 151 Mt. All of the repowering scenarios presented are potentially attractive, depending on economy-specific circumstances such as economic feasibility, availability of capital funds, access to alternate fuels and technology transfer and support issues. With the exception of scenario E17, repowering with IGCC or PFBCC, all repowering scenarios are based on technologies that are commercial and widely available in APEC. The viability of biomass repowering is very site specific and fuel supply and transportation will limit the scale of application at an individual site.

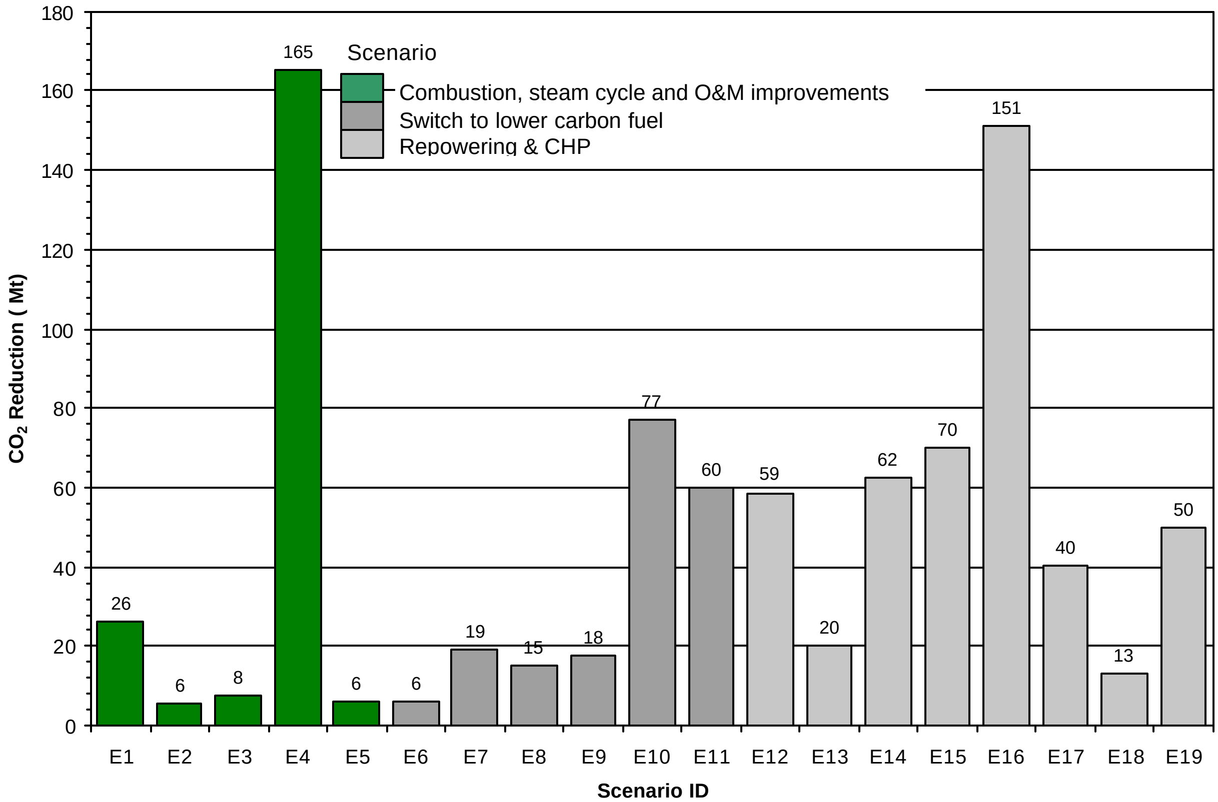

Figure S-1 CO_2 Emission Reductions Predicted for Application of Scenarios Throughout the APEC Region

The CO_2 emission reduction achievable by application of the identified scenarios to individual power plants was also determined on a generic basis. In this case, it was assumed that the scenario was applied to the same type of existing power plant and provided the same efficiency gain or reduction in CO_2 emission intensity as was used for the analysis of emission reductions in the APEC region.

Figure S-2 summarizes the impacts of application of each scenario to the target power plants, showing the reduction in CO_2 emissions, both in terms of the percent of the plant's initial emissions, and the CO_2 emission intensity in gCO_2/kWh. The results are shown in ranked order by gCO_2 reduced per kWh of electricity generated, from most to least effective. It is best to evaluate the options on this basis rather than as percent reduction, as it indicates the true emission reduction normalised to a constant output basis.

Implementation of CO_2 reduction options in the APEC region will also result in reductions in emissions of particulate matter, NO_x, SO_x, CO and VOC for all fossil fuels. These options would reduce emissions of hazardous air pollutants from coal fired power plants, with reductions in mercury emissions being most significant. The associated reduction in emissions of common and hazardous air pollutants will improve local and regional air quality in the vicinity of existing power plants and help to alleviate problems with long-range transport and acid rain that are commonly associated with power plant emissions in the APEC economies. The savings in health related damages resulting from improved air quality should be factored into analysis of the cost effectiveness of CO_2 reduction options.

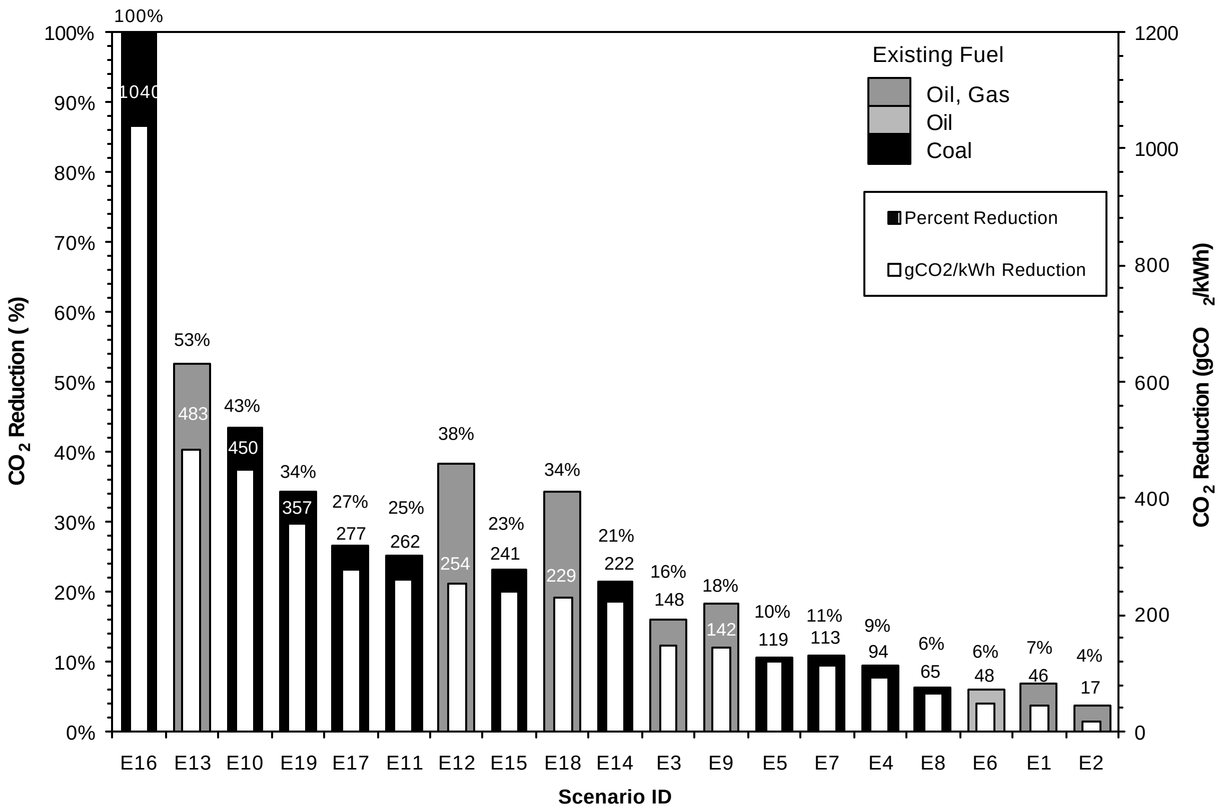

Figure S-2 CO_2 Emission Reduction in gCO_2/kWh for Individual Scenarios

Most of the CO_2 emission reduction scenarios reduce pollutant emissions from a power plant and, by so doing, create co-benefits in terms of improvements in air quality and a reduction in adverse effects from existing emissions. Environmental co-benefits of Scenarios E1 and E2 are minor as the reduction in emissions is anticipated to be small, in proportion to the change in plant efficiency. Scenarios E3-E5 have a somewhat higher potential for providing environmental co-benefits, though these also will be relatively small compared to the benefits for many of the other emission reduction scenarios. Scenario E10 is attractive because of switching to 100% natural gas, which is the cleanest burning fossil fuel, though, availability and cost is an obvious issue. Scenarios E12-E13 for oil/gas and Scenario E17 for coal offer substantial emission co-benefits because of the increase in fuel efficiency combined with improved pollution control that is integral to the current advanced systems. Repowering with CHP is beneficial because of the net reduction in fuel combustion and emissions that is achievable by displacing existing fuel combustion by waste heat recovery. The benefit of CHP is higher for coal firing than oil/gas firing because of the differences in emission characteristics of these fuels.

The results of this study suggest further work is needed in the following areas to fill data gaps and facilitate implementation of effective CO_2 emission reduction strategies for the electricity generation sector in the APEC region:

- identify barriers and means of reducing the barriers to accelerated adoption of supercritical and ultra supercritical boiler technology and advanced clean coal technologies in developing economies;
- for economies experiencing rapid growth in electricity generation, conduct detailed studies of the costs and benefits of implementing the more promising CO_2 emission reduction measures identified in this study;
- demonstrate the application of a range of combustion, steam cycle and O&M improvements, such as included in Scenario E4, in a developing APEC economy to quantify the improvements achieved (i.e., CO_2, common pollutants and performance), identify problems encountered and develop instructional and training materials needed to apply these techniques in other similar APEC economies; and
- investigate regulatory reforms and non-technical CO_2 emission reduction measures that are needed to support or enhance the implementation of more efficient energy technologies in the APEC region, such as those identified in this study.

Table S-1 Summary of Emission Reduction Scenarios Investigated

ID	Technology	Applicable Fossil Fuel	Applicable Technology*	1998 Plant Capacity (MW)	Assumed Percent Application to Existing Capacity (%)	Basis for CO_2 Reduction	Cost
E1	Combustion, Steam Cycle and O&M Improvements	Oil,Gas	ST Sub	289,149	50	2.5% efficiency gain	Low-Med
E2	Combustion, Steam Cycle and O&M Improvements	Oil,Gas	GTCC & CHP	110,846	50	2.0% efficiency gain	Low-Med
E3	Combustion, Steam Cycle and O&M Improvements	Oil,Gas	SC	119,062	50	5.0% efficiency gain	Low-Med
E4	Combustion, Steam Cycle and O&M Improvements	Coal	PC Sub, PC Super	610,409	50	3.5% efficiency gain	Low-Med
E5	Combustion, Steam Cycle and O&M Improvements	Coal	Stk/Cyc	33,653	50	3.5% efficiency gain	Low-Med
E6	Co-fire 25% Gas -plants with gas capability	Oil	ST Sub	125,116	28.7	Lower carbon fuel and no change in efficiency	Med
E7	Co-fire 25% Gas - plants with gas capability	Coal	PC Sub	492,920	6.1	Lower carbon fuel and no change in efficiency	Med
E8	Co-fire 25% Oil - plants with oil capability	Coal	PC Sub	492,920	8.2	Lower carbon fuel and no change in efficiency	Med
E9	Switch to 100% Gas - plants with gas capability	Oil	ST Sub	125,116	28.7	Lower carbon fuel and no change in efficiency	Med-High
E10	Switch to 100% Gas - plants with gas capability	Coal	PC Sub	492,920	6.1	Lower carbon fuel and no change in efficiency	Med-High
E11	Switch to 100% Oil - plants with oil capability	Coal	PC Sub	492,920	8.2	Lower carbon fuel and no change in efficiency	Med-High
E12	Repower with GTCC	Oil,Gas	ST Sub	289,149	20	Efficiency gain from 34% to 55%	High
E13	Repower with GTCC	Oil,Gas	SC	119,062	40	Efficiency gain from 26% to 55%	High
E14	Repower with PC Super	Coal	PC Sub	492,920	10	Efficiency gain from 33% to 42%	High
E15	Repower with AFBC and 20% Biomass	Coal	PC Sub, Stk/Cyc	526,573	10	Efficiency gain from 33% to 38% plus 20% biomass credit	High
E16	Repower with AFBC and 100% Biomass	Coal	PC Sub, Stk/Cyc	526,573	5	Efficiency gain from 33% to 38% plus 100% biomass credit	High
E17	Repower with IGCC or PFBCC	Coal	PC Sub, Stk/Cyc	526,573	5	Efficiency gain 33% to 45%	High
E18	Repower with CHP	Oil,Gas	ST Sub	289,149	5	Efficiency gain from 49% to 75%	High
E19	Repower with CHP	Coal	PC Sub	492,920	5	Efficiency gain from 49% to 75%	High

* See Abbreviations and Acronyms section for terms.

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ABBREVIATIONS AND ACRONYMS

AFBC	Atmospheric fluidized bed combustion technologies
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
APH	Air preheater
Btu	British Thermal Unit
CC	Combined cycle (either IC Engine or Gas Turbine with Steam Turbine)
CCT	Clean coal technology
CFD	Computational fluid dynamics
CHP	Combined heat and power
CH_4	Methane
CMMS	Computerized maintenance management systems
CO	Carbon monoxide
CO_2	Carbon dioxide
Cyc	Cyclone coal boiler
DCS	Digital/distributed control system
EWG	APEC Energy Working Group
FD	Forced draft (fan)
FGD	Flue gas desulphurisation (post-combustion SO_2 removal)
g	gram
GDP	Gross domestic product
GHG	Greenhouse gas emissions
GT	Gas turbine
GTCC	Gas turbine combined cycle
h	Hour
HP	High pressure
HRSG	Heat recovery steam generator
I&C	Instrumentation and controls
IC	Internal combustion engine
ID	Induced draft (fan)
IEA	International Energy Agency
IGCC	Integrated (coal) gasification combined cycle
IP	Intermediate pressure
IPCC	Intergovernmental Panel on Climate Change
J	Joule
lb	Pound
LP	Low pressure
LNB	Low NO_x burner
LOAEL	Lowest observed adverse effects level
m	meter

MTBF	Mean time between failures
N_2O	Nitrous oxide
NO_x	Nitrogen oxides, reported as NO_2
O&M	Operation and maintenance
OEM	Original equipment manufacturer
OPM	Online performance monitoring
Pa	Pascal (unit or pressure)
PA	Primary air (PC transport air)
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PFBCC	Pressurized fluidized bed combined cycle
PLC	Programmable logic controls
PM	Total suspended particulate matter
$PM_{2.5}$	Particulate matter having an aerodynamic diameter of 2.5 microns, or less
PM_{10}	Particulate matter having an aerodynamic diameter of 10 microns, or less
PPP	Purchasing power parity basis for GDP
RCM	Reliability centered maintenance
SC	Simple Cycle (either IC Engine or Gas Turbine)
SI Prefixes	kilo (k)= 10^3; mega (M)= 10^6; giga (G)= 10^9; tera (T)= 10^{12}; peta (P)= 10^{15}.
SO_2	Sulphur dioxide
SO_x	Sulphur oxides, reported as SO_2
SPC	Statistical process control
ST	Steam turbine
Stk	Stoker coal boiler
t	Metric tonne (tonne)
ton	Imperial ton (2000 lb)
TSP	Total suspended particulate matter (same as PM)
UDI	Utility Database Institute, UDI/McGraw-Hill Energy, Washington, DC, USA
UNEP	United Nations Environment Programme
U.S.	United States of America
US$	Dollars of the United States of America
U.S. EIA	United States Energy Information Administration
U.S. EPA	United States Environmental Protection Agency
VOC	Volatile organic compounds, excluding methane and ethane
VSD	Variable speed drive
W	Watt
WHO	World Health Organisation
yr	Year
η	Net plant energy efficiency in percent of LHV
$\Delta\eta$	Incremental change of net plant efficiency in percent LHV
$\mu g/m^3$	Micrograms per cubic meter

%	Percent change from a reference level
% points	Incremental change in the percentage value

1. INTRODUCTION

1.1 BACKGROUND

The APEC economies account for 64% of global economic activity and 42% of the world's population. Related to these factors, APEC economies collectively consume 59% of the world's energy requirements and emit 59% of the world's carbon dioxide from fuel combustion. The share of the world's energy use occurring in APEC economies is likely to increase.

Electricity generation is a major consumer of energy worldwide. In 1999, the energy consumed for electricity generation in the form of oil, natural gas, coal, nuclear, hydropower and renewable fuels amounted to 156,562 PJ and comprised 38.9% of the 402,799 PJ of total energy consumption world-wide (U.S. EIA, 2001a). Net electricity consumption is forecast to grow worldwide at a rate of 2.7% per year over the period from 1999 to 2020. The growth rate is forecast to be highest in developing Asia at 4.5% per year, and lowest in industrialised Asia at 1.3% per year and North America at 2% per year.

Energy requirements for power generation in the world are projected to increase at an average annual rate of 2.0% through to 2020, resulting in a 52% increase in total energy consumption from the level in 1999 and resulting in a total demand of 237,797 PJ. The contributions of oil and renewable (predominantly hydropower) energy to the total energy used for power generation are projected to remain relatively constant to 2020 at about 10% and 20%, respectively. Over this period, the share of total energy used for power generation from natural gas is projected to increase from 18.8% to 26.5%, while the share from coal will decrease from 34.1% to 30.9% and the share from nuclear will decrease from 17.0% to 12%.

The growth in energy used for electricity generation in developing economies in the APEC region is substantially higher than the average rate projected world-wide because of the increase in electrification to improve economic development and standard of living, combined with population growth. APERC (1998) has forecast that electricity consumption in the APEC region will grow at an annual rate of 3.2% per year over the period from 1995 to 2010 (1998 baseline case), which would result in a 60% increase in energy consumption for this sector from 6,837 TWh in 1995 to 10,942 TWh in 2010. Growth in electricity consumption in this period exceeds forecast GDP growth in the APEC region, which was assumed at that time to be 2.3-2.4% per year for 2000-2010. The U.S. Energy Information Administration (2001) forecasts electricity consumption in the APEC region will grow at a somewhat slower rate of about 2.8% per year over the period from 1999 to 2020 . At this average growth rate, net electricity consumption in the APEC region will grow from 7,543 TWh in 1999 (APEC, 2001) to 13,470 TWh in 2020, an overall increase of 79%.

Total electricity generation in APEC was 8665 TWh in 1999. On an output basis, 68.3% was produced using fossil fuels, followed next by nuclear energy at 16.2%, hydropower at 14.7% and other fuels at less than 1%. The significance of fossil fuels in the fuel mix for electricity generation in the APEC region increases when examined on the basis of input energy. In this case, fossil fuels comprise 74.6% of the input energy used to generate electricity, while nuclear comprises 18.1%, hydropower comprises 5.4% and geothermal and other sources comprise less than 2%.

The projected growth in electricity consumption combined with the currently high reliance on fossil energy for electricity generation in the APEC region makes this sector a significant current and continuing contributor to emissions of greenhouse gases and air pollutants. Thermal generation of electricity from fossil fuels contributes to air pollution, adverse health impacts, acid rain and haze from emissions of particulate matter, NO_x, SO_x, air toxics and other contaminants. The IEA (1999a) forecast that world-wide carbon dioxide emissions from burning of coal, oil and gas for power generation will increase from 7,663 Mt in 1997 to 13,479 Mt in 2020, an increase of 2.5% per year, or 76% overall (IEA reference scenario). The share of total worldwide CO_2 emissions contributed from burning fossil fuels for electricity generation was 33.3% in 1997 and is projected to increase to 37% by 2020. Significant increases can also be expected for air pollutants, depending on current and future emission standards, and future advances in emission control over the forecast period.

Fossil fuel combustion for power generation in APEC economies generates approximately 42% of the total CO_2 emissions from fuel combustion in the APEC region, and 24.5% of the CO_2 emissions from fuel combustion in the world. Associated with these emissions are substantial emissions of common and toxic air contaminants and associated secondary impacts.

The Expert Group on Clean Fossil Energy promotes the use of clean fossil fuels and advanced conversion technologies that increase energy efficiency and reduce environmental impacts from use of fossil fuels. As member economies have different energy resources and different needs to support economic development, the Expert Group develops information and promotes a wide range of energy options that can be applied to meet the diverse energy, economic and environmental needs in the APEC region. Increasingly, environmental factors influence energy and technology choices, with coal and natural gas likely to play major roles in the future energy supplies for many APEC member economies.

This study was undertaken to help APEC member economies address greenhouse gas emissions and environmental issues associated with use of fossil energy to generate electricity. The study furthers APEC's objectives by expanding the information available on methods for improving the efficiency of current technologies and on the performance of alternative and emerging technologies.

The Expert Group retained Levelton Engineering Ltd. to undertake this study with the voluntary assistance of many participants in APEC member economies that provided information on energy use, the existing and planned electricity generating capacity, the efficiency of in-use power generating plants, potential technology and operational improvements to improve generating efficiency and emissions for the electricity sector. A steering committee provided technical review and direction, with representatives from the Republic of Korea, People's Republic of China, Japan and Canada. The U.S. Department of Energy assisted with support for missions to member economies to improve the data available for the study.

1.2 Scope of Work

The study focuses on the electricity generation sector in the APEC region. The principal goals of the study were: 1) to review current and emerging options to improve efficiency and reduce CO_2 emissions from burning fossil fuels to generate electricity; 2) to develop data on the status of current CO_2 emissions and CO_2 emission reduction measures from the electricity generation sector; and 3) to determine the current effects of emissions from combustion of fossil fuels for electricity generation on air quality and health and the possible effects of CO_2 reduction options on air quality. The study was intended to identify the options available to reduce CO_2 emissions from existing and planned power plants for the APEC region, and, at a screening level of detail, to identify the more promising options. Analysis of the cost effectiveness of CO_2 emission reduction options or the economic feasibility of CO_2 reduction options for specific APEC economies or power plants is outside the scope of work.

The study is supportive of the goals of APEC programs to reduce the environmental impacts of energy production, delivery and consumption, to foster a common understanding of regional energy and environmental issues, and to strengthen economic infrastructure by identifying new approaches to efficiently combust fossil fuels or to capture CO_2 emissions during combustion of fossil fuels.

As described in the request for proposal, this study included completion of the following tasks:

- Prepare a detailed survey questionnaire for the review and approval by the project task group;
- Compile a questionnaire mailing/email list with input from the project task group;
- Distribute questionnaires according to the distribution list and conduct enquiries with those contacted to help obtain as complete a response to the survey as possible;
- Travel to economies where the power sector is large and/or is expected to grow substantially to gather data directly and maximize the quality and completeness of the survey responses;
- Compile and analyse the survey data, including preparation of tables and graphs and illustration of trends or patterns in the data;
- Conduct an analysis of the impact of currently in use technologies to reduce CO_2 emissions from the power generation sector.
- Prepare a draft report;
- Brief the Expert Group on the results in the draft report; and
- Prepare a final report in the required number of copies and electronically.

2. METHODOLOGY AND SOURCES OF DATA

2.1 SURVEY TO COLLECT DATA FROM APEC ECONOMIES

2.1.1 Survey Development and Content

A survey was undertaken through government and corporate contacts in all the APEC economies as a means of gathering key information needed for the study on electricity generation plants fuelled using coal, natural gas or oil. Other sources of information were used to supplement the information obtained by using the survey, as this provided a wider base of data for the study and made available information from studies of the electricity generation sector in various APEC economies. One of the goals of the survey was to compile data characterizing the technologies currently used to generate electricity in each APEC economy, and the generating capacity and energy conversion efficiency for sub-groups of facilities by fuel type and technology type. In addition, the survey aimed to obtain information on generating capacities and types of energy technologies planned to be used in future electricity generating facilities and on the approaches being considered, or that have been implemented, to reduce greenhouse gas emissions from burning fossil fuels in the power sector.

An initial draft of a questionnaire for the survey was prepared by the project team and circulated to the project committee for review and comment. Feedback received from the project committee was used to prepare a final version of the questionnaire (Appendix A) that was then distributed to contacts in APEC economies. As described below, these contacts included representatives in the ministries of energy, industry, and environment in each APEC economy, as well as academics in the research and development sector and representatives from major electricity utility companies.

2.1.2 Distribution and Follow-up

The questionnaire was distributed by email, facsimile and mail in March and April of 2001 to 124 public utility companies and 173 representatives of government agencies in the 21 APEC economies. The contact list was compiled from previously contacted representatives and contributors to the December, 2000 APEC Study on the Role of Petroleum Based and Alternative Transportation Fuels in Reducing Emissions in the APEC region. The questionnaire was distributed preferentially by electronic communication, followed by fax and mailing. The initial distribution of questionnaires was followed up by email in May and June to improve the response rate for the questionnaire, which had been poor to that date. A second distribution of the questionnaire was carried out using the earlier contact data base together with additional contacts identified through various means. Unfortunately completed surveys were received from only 6 of the 21 APEC economies.

2.2 DATA COLLECTION MISSIONS TO APEC ECONOMIES

Information needed for the study was collected from Malaysia, the People's Republic of China and other economies by attendance at Power-Gen Asia 2001 which was held in September in Kuala Lumpur, Malaysia, and meetings with contacts in government and the private sector in Malaysia and PR China. The organizations visited to discuss the study and data needs are listed below:

Malaysia

- Conservation and Environmental Management Division. Ministry of Science, Technology and the Environment.
- Department of Electricity and Gas Supply (Energy Commission)
- Malaysian Meteorological Service
- Malaysian Energy Centre.
- Ministry of Energy, Communications & Multimedia

People's Republic of China

- Thermal Power Research Institute, State Power Corporation of China
- Center of Environmental Sciences, Peking University
- Chinese Research Academy of Environmental Sciences
- Energy Research Institute, State Development Planning Commission of Chinese Academy of Sciences
- China Power Engineering Consulting Corporation
- Institute of Environmental Science and Engineering, Tsinghua University
- China Electricity Council International

2.3 OTHER SOURCES OF DATA FOR THE STUDY

As a starting point for this study and to supplement the information obtained by survey, the World Electric Power Plants Database compiled by UDI/McGraw-Hill Energy was purchased. This database contains individual listings for most power plants in all APEC economies, including power plant capacity, energy technology used, fuel type, steam pressure and temperature, date of initial operation, plant location, amongst other information. Although the UDI database contains data on the type of technology used in a large number of power plants, this information is missing for some of the plants located in developing APEC economies. Data from the UDI database were used extensively for this study and was compared to survey responses and other independent data sources to assess the representativeness of the data.

A search of major indexes of published literature and of the Internet was conducted to identify and obtain data relevant to the study. This search process identified a large amount of information useful to the study and a number of key government agencies and international organizations. The reference list provided at the end of the report lists all of the sources of information cited in the report. The main sources of energy statistics and emission data for individual countries and the APEC region in general were:

- Asia Pacific Economic Cooperation
- Asia Pacific Energy Research Center
- International Energy Agency

- Energy Data and Modelling Center, The Institute of Energy Economics, Japan
- CIA world fact book
- United States Energy Information Administration
- World Energy Council
- Government energy and environmental agencies in APEC member economies.

2.4 DATA ANALYSIS

Data on primary energy use, the quantities of fossil fuels used for power generation, and the quantity of electricity generated and used in each economy were obtained largely from APEC, the U.S. Energy Information Administration and the International Energy Agency publications and databases. Information on the quantity of CO_2 emitted in total and from the electricity generation sector only was obtained for each APEC economy from an IEA report issued in 2000 on CO_2 emissions from fuel combustion. This information was manipulated, as needed, to analyse the energy sector and prepare comparative graphs for use in the study.

The limited responses from the survey of APEC economies were compiled for illustration of trends and comparisons. Selected data from the survey were also used to help assess the representativeness of the data extracted for analysis purposes from the UDI database.

Data from the UDI/McGraw-Hill Energy database on global electricity generation facilities were analyzed extensively to characterize the existing plants and the planned new power generation facilities in the APEC economies. Data from UDI for each power plant regarding generating capacity, type of fuel and energy technology, and plant location were used for the analysis of CO_2 emission reduction options discussed in Chapter 5 of this report. Chapter 3 presents a discussion that characterizes the electricity generation sector in the APEC economies, including generation capacities and production, distribution of fuels used, CO_2 emissions and related economic indicators.

3. Electricity Generation and Related Data in the APEC Region

3.1 Data Compiled and Used in This Study

Data were compiled from a variety of sources, but primarily from databases, publications and web pages prepared by APEC, UDI/McGraw-Hill Energy, the U.S. Energy Information Administration, the International Energy Agency, and individual economies. The main recent statistics assembled for use in the study were population, gross domestic product, electrical generating capacity, annual electricity generation and consumption, and annual carbon dioxide emissions for each of the 21 APEC economies. Data on electricity were totalled in both GW capacity and GWh generation per fuel source. Information on the electricity generation technologies and the efficiencies of these technologies has been surveyed for the APEC economies that completed the survey. Data for the APEC economies were also developed from detailed analysis of the UDI database of worldwide power generating facilities. APEC data has been compared to world totals where useful for a perspective on the contribution of APEC economies and in understanding energy and technology trends.

The following sections in the Chapter characterize the electricity generation sector in the APEC economies, present tables and charts illustrating similarities and differences in this sector between countries and summarize the current situation. The data are used later in this report for the analysis of the effects of various CO_2 emissions reduction options. This Chapter was developed from available sources, including the results of the survey conducted for this study, publications from various agencies and internet web pages. The sources of the information are indicated throughout.

3.2 Population and Economic Data

Table 3-1 presents a summary of data on land area, population (1998, 1999 and 2000 from different sources) and gross domestic product for the APEC economies. The APEC region has a combined population of approximately 2.6 billion people, which amounts to 42% of the current estimated world population of 6.16 billion (U.S. Bureau of the Census, 2001). The People's Republic of China has the largest population in the APEC region, at 1.28 billion people and 49.4% of the region's combined population. The next four most highly populated economies in APEC are the United States of America (11.0%), Indonesia (8.7%), Russia (5.6%) and Japan (4.9%). These five economies account for 79.6% of the region's total population. Figure 3-1 illustrates current population statistics for the APEC economies.

The population growth rate within APEC varies between 0.18% in Japan to 3.54% in Singapore. Overall, the population weighted average growth is about 1.0%. Figure 3-2 illustrates the current trends in population growth for the APEC economies.

Table 3-1 Land Area, Population and Gross Domestic Product for APEC Economies

Economy	Area*	Population				Market Exchange Rate GDP		Real GDP Growth Rate**	GDP/Capita
		1998†	1999††	2000E**		2000E**		2000	2000
	(Square km)	(Million)	(Million)	(Million)	(% APEC)	(Billion US$)	(% APEC)	(%)	(US$/person)
Australia	7,682,000	18.75	19.2	19.2	0.7	380	1.9	4.00	19,797
Brunei Darussalam	5,765	0.32	.34	0.3	0.0	6	0.0	3.50	20,000
Canada	9,984,670	30.3	31.3	31.3	1.2	692	3.5	4.70	22,102
Chile	757,000	14.82	15.2	15.2	0.6	70	0.4	5.40	4,605
PR China	9,600,000	1,238.6	1,261.8	1,278.6	49.4	1,131	5.7	8.00	885
Chinese Taipei	36,000	21.87	22.2	22.2	0.9	330	1.7	6.40	14,865
Hong Kong, China	1,097	6.69	7.1	6.8	0.3	170	0.9	10.00	25,000
Indonesia	1,937,179	203.68	224.8	224.8	8.7	157	0.8	5.10	698
Japan	377,800	126.49	126.5	126.5	4.9	4,775	24.0	2.00	37,747
Malaysia	329,750	22.18	21.8	21.8	0.8	86	0.4	7.50	3,945
Mexico	1,964,375	95.68	100.3	100.3	3.9	578	2.9	6.90	5,763
New Zealand	268,680	3.79	3.8	3.9	0.2	49	0.2	2.60	12,564
Papua New Guinea	462,000	4.21	4.9	4.9	0.2	12	0.1	3.60	2,449
Peru	1,285,216	24.8	27.0	27.0	1.0	54	0.3	3.60	2,000
Philippines	300,000	75.17	81.2	81.2	3.1	75	0.4	4.10	924
Republic of Korea	99,408	46.43	47.5	47.9	1.9	468	2.4	9.10	9,770
Russia	17,000,000	146.91	146.0	146.0	5.6	207	3.1	6.20	1,418
Singapore	647.5	3.16	4.2	3.3	0.1	92	0.5	9.80	27,879
Thailand	513,115	61.2	61.2	62.9	2.4	126	0.6	4.60	2,003
United States	9,372,610	269.09	275.6	284.0	11.0	9,974	50.2	5.00	35,120
Vietnam	331,111	76.52	78.8	78.8	3.0	34	0.2	6.00	425
Totals	62,308,424	2,490.66	2,560.7	2,586.9	100	19,881	100	-	-

Sources: * APERC web page; ** U.S. EIA web page for APEC; † IEA, 2000a; †† www.odci.gov/cia/publications/factbook/geos

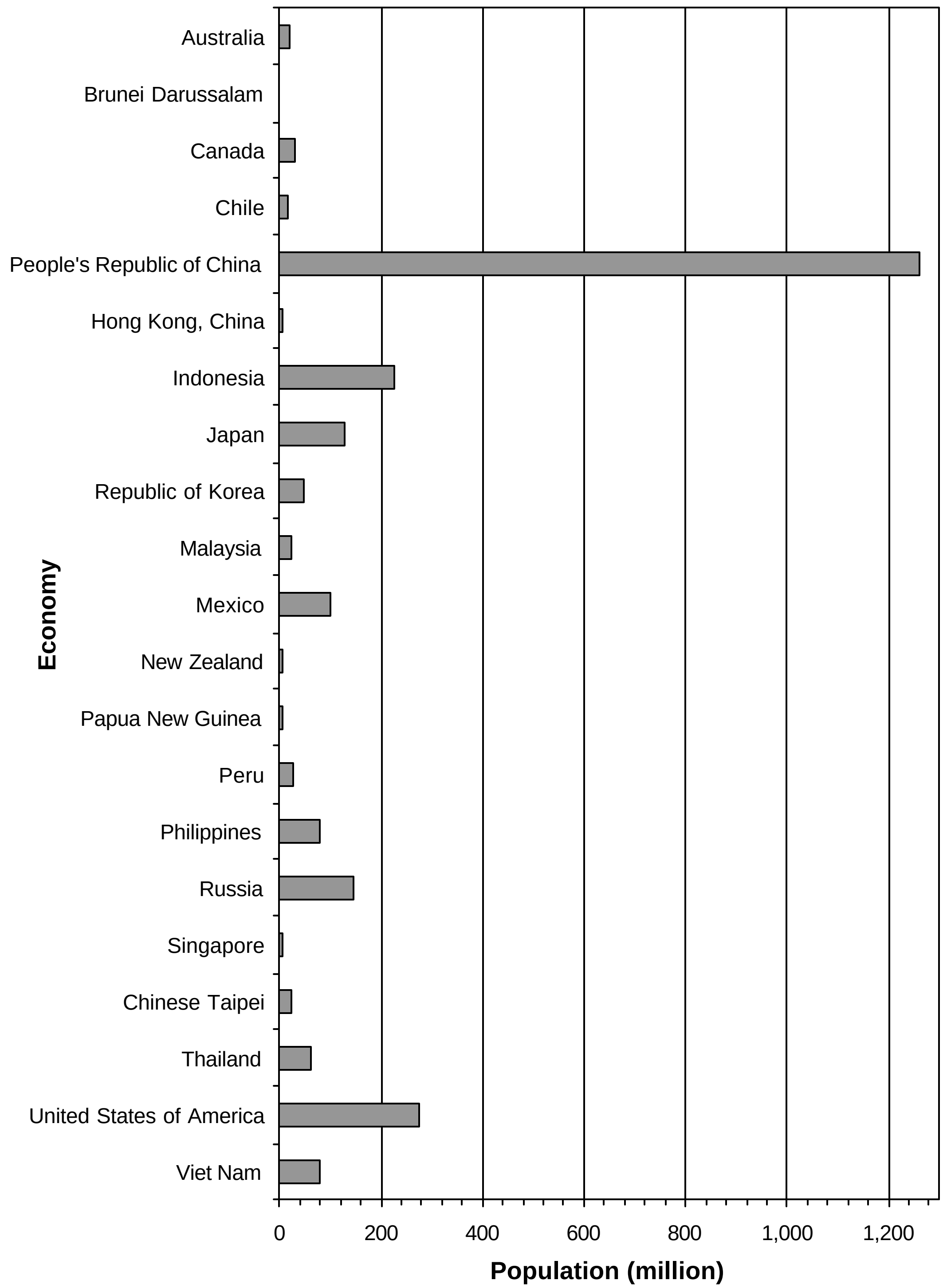


Figure 3-1 Population of APEC Economies in 1999

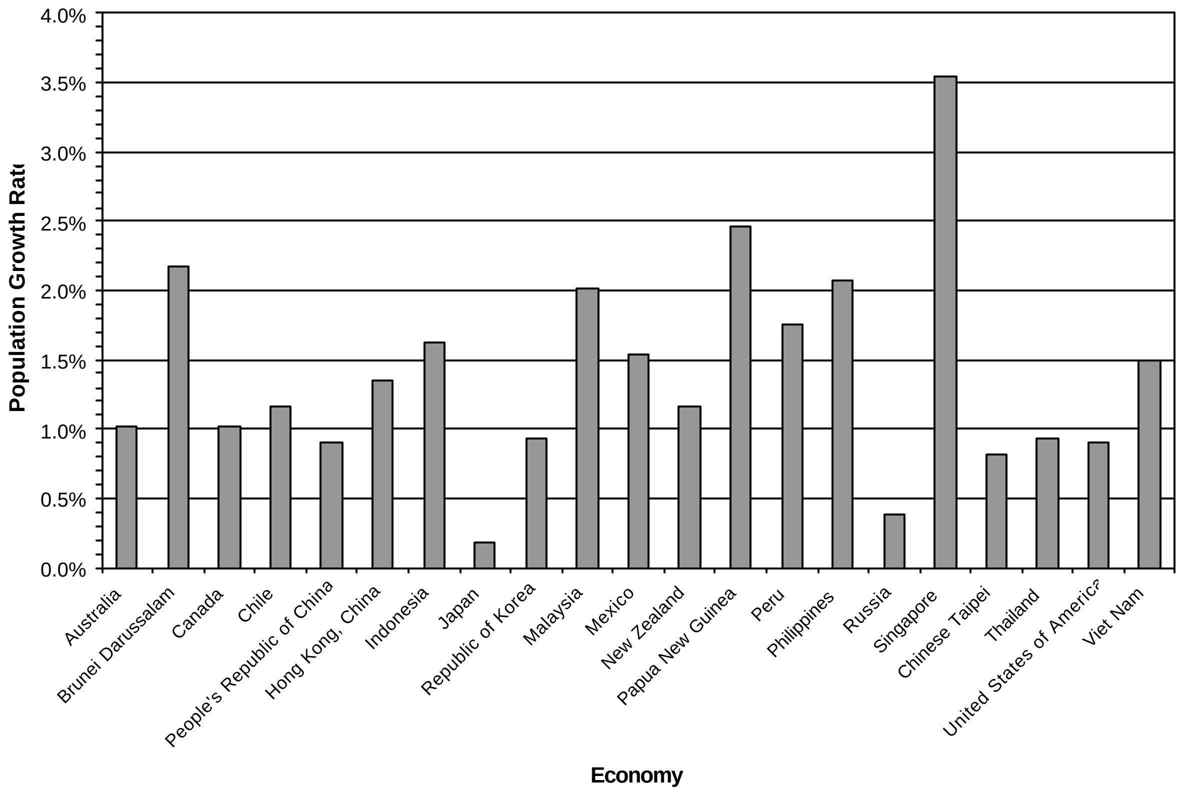


Figure 3-2 Population Growth Rate in APEC Economies in 1999

The economies with the five largest GDP/capita (based on market exchange rates) in U.S. dollars are Japan, the United States of America, Singapore, Hong Kong China, and Canada. As shown in Table 3-1, nominal GDP/capita in 2000 ranges from US$ 425/person in Vietnam to US$ 37,747 in Japan. The average GDP/capita is US$ 11,900/person.

Data on gross domestic product in terms of purchasing parity in U.S. dollars are available for 1999 for the APEC region (U.S. CIA, 2001). The 1999 US$GDP per capita assuming purchasing power parity (PPP) for APEC economies are compared in Figure 3-3. The economies having the five largest GDP(PPP)/capita are the United States (US$ 33,586/person), Singapore (US$ 23,607/person), Japan (US$ 23,311/person), Canada US$ 23,091/person) and Hong Kong (US$ 22,231/person). Seven APEC economies have values of US$GDP(PPP)/person below US$ 5,000/person. The average GDP/capita level is US$ 12,884/person.

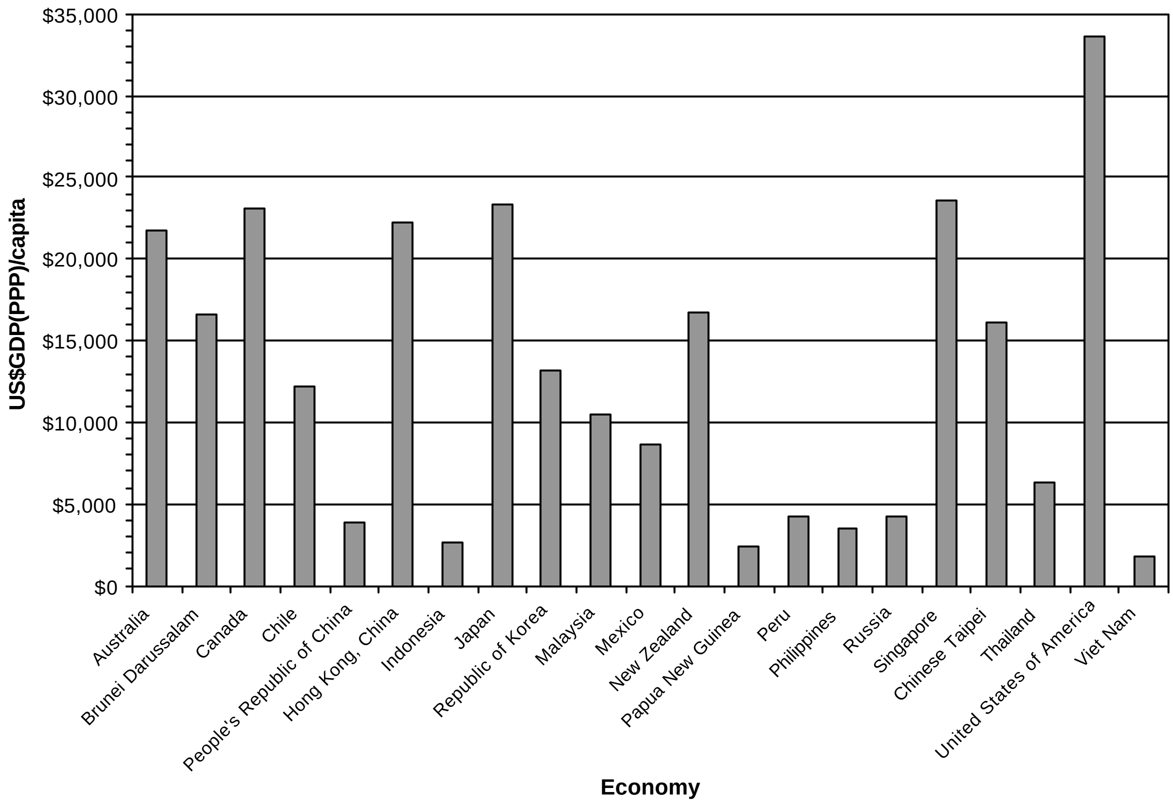


Figure 3-3 U.S. Dollar Gross Domestic Product (Purchasing Power Parity) per Capita in APEC Economies for 1999

3.3 ENERGY RESOURCES

Table 3-2 summarizes the proven reserves and 1999 production levels for fossil fuels in each of the APEC economies. Indigenous reserves and production capacity are significant considerations with regard to understanding the current fuel mix used for electricity generation and identifying viable options for reduction of greenhouse gases appropriate to individual APEC economies. The six largest coal producing economies are PR China, the United States, Australia, Russia, Canada and Indonesia, which collectively produce 98% of the total production in the APEC region. Russia, the United States, Canada, Indonesia and Australia produce about 91% of the natural gas in the APEC region. The five largest producers of petroleum are the United States, Russia, Mexico, PR China and Canada, totalling 86% of the total production in the region. Hong Kong China, Singapore, Korea and Chinese Taipei have very low or negligible proved reserves of fossil fuels, while a number of economies have reserves, but currently low production levels.

Table 3-2 Energy Supply Indicators for APEC Economies

APEC Economy	Fossil Fuel Proved Reserves			Fossil Fuel Production, 1999		
	Crude Oil 1/1/01 (10^6 m^3)	Natural Gas 1/1/01 (10^9 m^3)	Coal 12/31/97 (10^9 tonnes)	Petroleum[1] (10^3 m^3/day)	Dry Natural Gas (10^9 m^3)	Coal (10^6 tonnes)
Australia	460.3	1,263	90.4	95.4	31.1	291.2
Brunei	214.6	391	0	31.8	8.5	0
Canada	748.2	1,727	8.6	413.4	178.4	72.6
Chile	23.8	99	1.2	3.2	2.8	0.9
PR China	3,815.7	1,368	114.5	508.8	25.5	1,014
Hong Kong, China	0	0	0	0	0	0
Indonesia	791.8	2,047	5.3	254.4	65.1	64
Japan	9.4	40	0.8	15.9	2.8	3.6
Malaysia	620.0	2,313	0	127.2	42.5	0.4
Mexico	4,493.0	861	1.2	540.6	36.8	10.0
New Zealand	20.2	71	0.5	15.9	5.7	3.6
Papua New Guinea	52.9	224	0	15.9	0	0
Peru	57.2	246	1.1	15.9	2.8	0
Philippines	45.9	79	0.3	0	0	0.9
Russia	7,722.5	48,139	157.0	1,001.6	589.0	250.4
Singapore	0	0	0	0	0	0
South Korea	0	0	0.1	0	0	4.5
Chinese Taipei	0.6	76	0	0	0	0.09
Thailand	56.0	334	2.0	15.9	17.0	18.1
United States	3460.4	4,740	249.6	1430.9	526.7	997.0
Vietnam	95.4	193	0.2	47.7	0	10.9
Total	22,687.9	64,211	632.7	4,515.2	1,534.8	2,742

[1] Includes crude oil, natural gas plant liquids, other liquids, and refinery processing gain.

Source: Converted to metric units from data provided on U.S. EIA web page (www.eia.doe.gov/emeu/cabs/apec.html) which cites the following sources of data: Crude Oil and Natural Gas Reserves: PennWell Publishing Co., *Oil & Gas Journal*, 12/20/00. Crude Oil Refining Capacity: PennWell Publishing Co., *Oil & Gas Journal*, 12/20/00. All Other Data: Energy Information Administration, International Energy Database, February 1, 2001.

3.4 OVERVIEW OF ELECTRICITY ENERGY DEMAND AND FUEL USE

Data are available for all APEC economies on the power generation capacity and annual electricity generation in 1998. These results, which are shown in Table 3-3, illustrate the overall distribution of generating capacity and annual generation within the APEC region. APEC has compiled the same information for 1999, however, data for electricity generation capacity in Russia and Papua New Guinea are missing and, for this reason, the 1999 APEC data was not used in this study. APEC data shows that both total and thermal annual electricity generation in APEC grew 3.3% from 1998 to 1999. Total and thermal generating capacity in the APEC region grew at a much slower pace of 1.1% and 0.6%, respectively, from 1998 to 1999, according to APEC data for all economies except Russia and Papua New Guinea, for which data for 1999 are not available.

The total capacity in 1998 of electricity generation facilities within the APEC economies based on data reported to APEC (2000) is 1,887 GW. The total operating electricity generating capacity in the APEC region in 1998 according to the UDI database is 1,878 GW, which is only 0.5% less than that reported for 1998 by APEC and, hence, agrees very well. Fossil fuels (oil, natural gas and coal) are used to fire just under 70% of the existing electricity generating capacity in the APEC region (Table 3-3). The balance is hydropower (19.3%), nuclear power (10.5%) and other energy sources (0.5%), supplied using geothermal energy or renewable fuels.

As shown in Table 3-3, the quantity of electricity generated in the APEC economies in 1998 (APEC, 2001) was 8,383,562 GWh, with 68.3% from burning fossil fuels, 15.1% from hydropower, 15.8% from nuclear energy and less than 1% from geothermal energy and renewable fuels. This distribution parallels closely the distribution of generating capacity.

Based on data from the UDI database to November, 2000, which is the most up to date and comprehensive information available to this study, the APEC economies with the four largest electricity generating capacities over 200 GW are the United States, PR China, Japan and Russia. These APEC economies account for 83.6% of the total regional generating capacity. The same economies also have the four highest thermal power generating capacities, which together comprise 80.8% of the thermal generating capacity in APEC. The distribution of total current generating capacity among the APEC economies, according to the UDI database, is illustrated graphically in Figure 3-4. Electricity generating capacities for each of the APEC economies by energy source are summarized in Table B-1 (Appendix B) for the operating facilities updated to November, 2000, and in Table B-2 for the facilities operating in 1998.

Fossil fuels are used in thermal power systems in the United States, PR China, Japan and Russia to generate 81.9% of the total GWh of electricity generated in the APEC region. These economies also account for 79.1% of the total GWh of electricity generation from all energy sources.

Table 3-3 Electricity Generating Capacities and Annual Electricity Generation in APEC in 1998

APEC Economy	Electricity Generation Capacity						Electricity Generated						
	Thermal	Hydro	Nuclear	Others	Total		Thermal	Hydro	Nuclear	Geothermal	Others	Total	
	MW	MW	MW	MW	MW	%	GWh	GWh	GWh	GWh	GWh	GWh	%
Australia	31,891	7,491	0	3	39,386	2.1	179,792	16094			8	195,894	2.3
Brunei Darussalam	769	0	0	0	769	0.04	2,807					2,807	0.03
Canada	35,273	61,379	13,195	23	109,870	5.8	159,451	332000	67467		200	559,118	6.7
Chile	3,721	3,825	0	0	7,546	0.4	19,357	16152				35,509	0.4
PR China	209,884	65,065	2,100	240	277,289	14.7	944,100	208000	14100			1,166,200	13.9
Chinese Taipei	16,311	4,288	5,144	0	25,743	1.4	115,754	10608	36824			163,186	1.9
Hong Kong, China	11,312	0	0	0	11,312	0.6	31,414					31,414	0.4
Indonesia	17,935	3,065	0	363	21,364	1.1	62,345	10558		3848		76,751	0.9
Japan	159,054	45,382	45,248	606	250,290	13.3	578,479	99612	327296	3596	19440	1,028,424	12.3
Malaysia	11,502	2,104	0	0	13,606	0.7	56,579	4852				61,431	0.7
Mexico	23,495	9,700	1,309	752	35,256	1.9	131,316	24657	9338	5667	5	170,983	2.0
New Zealand	2,422	5,159	0	522	8,103	0.4	9,500	24124		2338	529	36,492	0.4
Papua New Guinea	335	155	0	0	490	0.0	1,304	868				2,172	0.0
Peru	2,943	2,572	0	0	5,516	0.3	4,779	13814				18,593	0.2
Philippines	7,907	2,304	0	1,856	12,067	0.6	16,595	5066		8914	11003	41,578	0.5
Republic of Korea	28,259	3,131	12,016	0	43,406	2.3	119,512	6099	89689			215,300	2.6
Russia	148,400	43,700	21,300	0	213,400	11.3	564,600	159000	103500	30		827,130	9.9
Singapore	5,521	0	0	0	5,521	0.3	27,685				739	28,424	0.3
Thailand	14,584	2,923	0	1	17,508	0.9	84,890	5177		2		90,069	1.1
United States	583,623	98,740	97,070	5,113	784,546	41.6	2,603,105	318889	673702	14726		3,610,422	43.1
Vietnam	1,606	2,854	0	0	4,460	0.2	10,573	11092				21,665	0.3
Total	1,316,747	363,837	197,382	9,479	1,887,448	100	5,723,937	1,266,662	1,321,916	39,121	31,924	8,383,562	100
Percent by Type	69.8	19.3	10.5	0.5	100	-	68.3	15.1	15.8	0.5	0.4	100	-

Source: APEC Database (APEC, 2001)

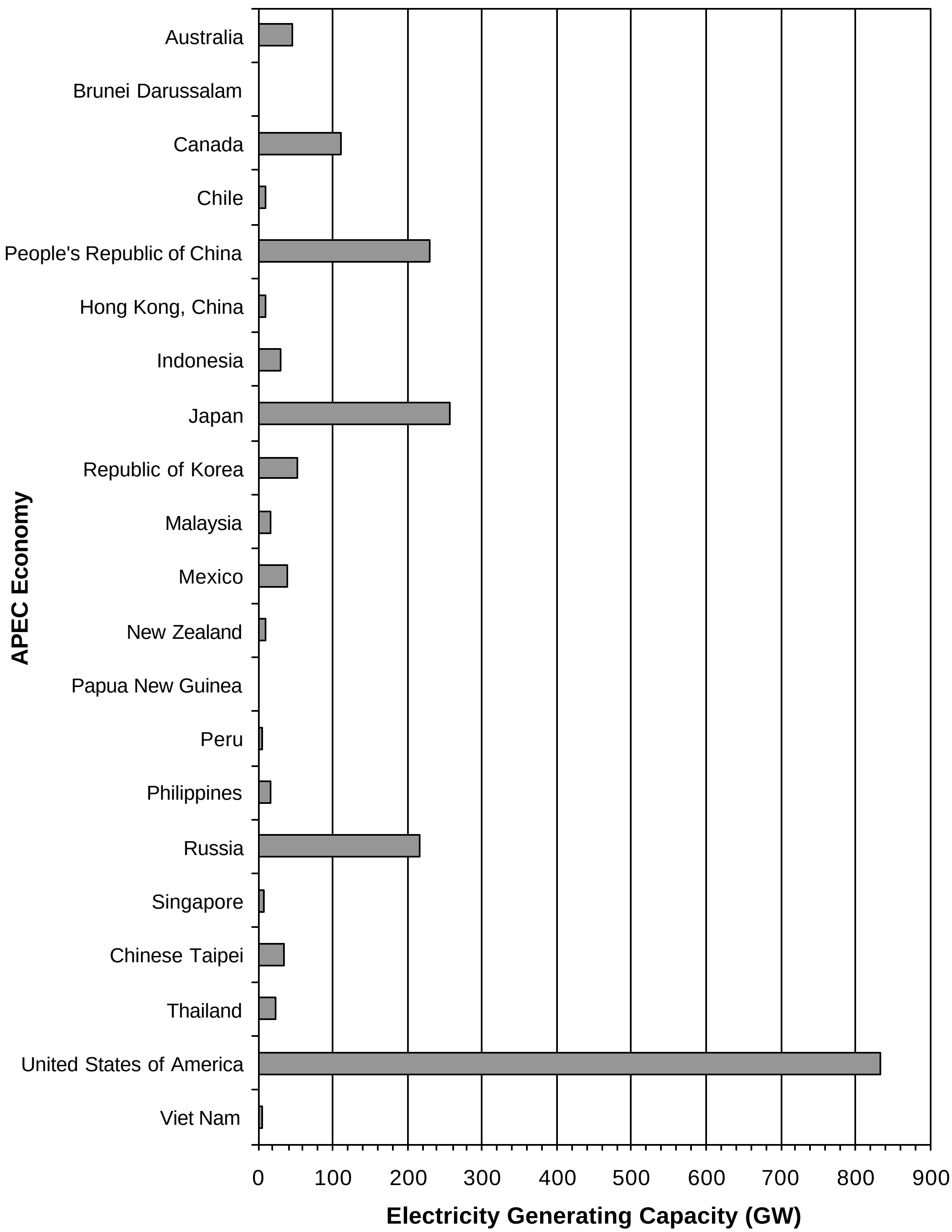


Figure 3-4 Electricity Generating Capacities for APEC Economies to November, 2000 According to UDI Database

The capacity data contained in the UDI data base were analyzed to determine the distribution of generating capacity in the APEC economies by fuel type. This data base identifies the following fuel categories: coal, oil, natural gas, hydroelectric, nuclear, waste fuel gas, solid waste, biomass, other zero greenhouse gas sources; and additional unspecified technologies. The UDI data indicates fossil-fuels fire 67.6% of APEC's electricity generating capacity, which agrees well with the data from APEC that indicates a level of 69.8%. Coal-fired power plants make-up the greatest percentage of capacity within the region at 34.4%, followed next by natural gas and oil (Figure 3-5). The fraction fired with coal varies from a low of about 15% in South American APEC economies to a high of about 47% in China and Russia (Table 3-4). Oil is used for the highest percentage of generating capacity in developing Asia, at 26.8%, and for about 10% of the capacity in North America.

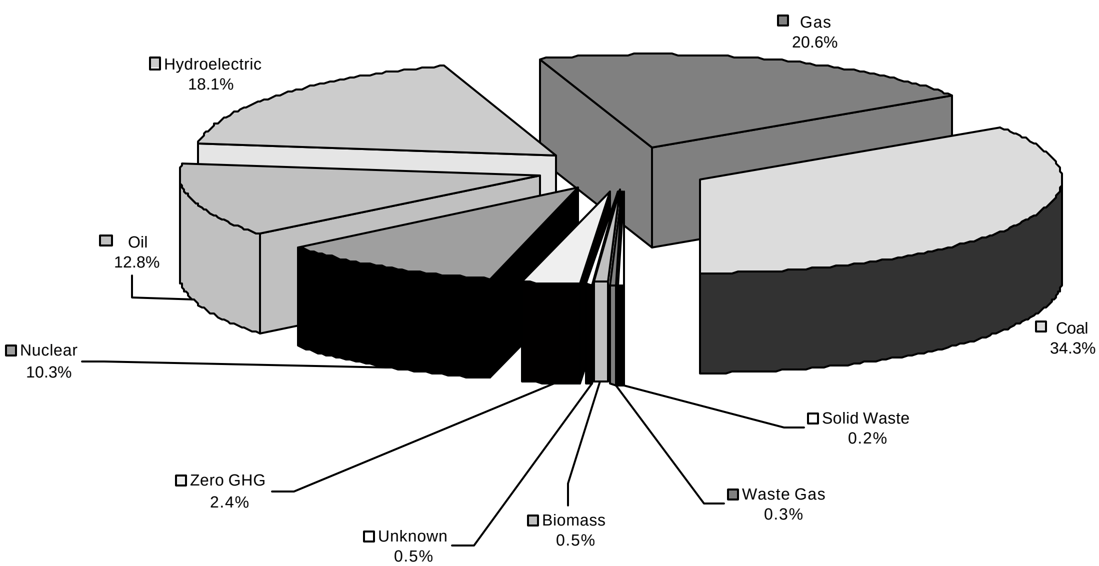


Figure 3-5 Distribution of APEC Electricity Generating Capacity by Fuel Type to November, 2000 According to UDI Database

Table 3-4 Distribution of Electricity Generating Capacity in the APEC Region by Fuel Type to November, 2000 According to UDI Database

Economy Grouping	Coal	Oil	Gas	Waste Gas	Solid Waste	Biomass	Hydro	Nuclear	Zero GHG[a]	Unknown
South America	15.2%	20.8%	13.3%	0.0%	0.0%	0.1%	45.9%	0.0%	3.6%	1.1%
Developing Asia	19.0%	26.8%	24.1%	0.1%	0.3%	0.8%	13.6%	3.7%	10.3%	1.2%
Russia & China	47.4%	6.1%	19.9%	0.1%	0.0%	0.3%	21.0%	4.9%	0.3%	0.0%
Australasia	19.8%	21.8%	20.1%	0.9%	0.0%	0.1%	16.9%	16.3%	1.7%	2.2%
North America	36.1%	10.4%	20.6%	0.2%	0.3%	0.8%	17.5%	11.6%	2.5%	0.0%
Total	34.4%	12.7%	20.5%	0.3%	0.2%	0.5%	18.1%	10.3%	2.4%	0.5%

a Zero GHG refers to geothermal steam, solar thermal, solar voltaic, wind, and tidal power, which are generally accepted to generate zero greenhouse gases.

The International Energy Outlook for 2001 (U.S. EIA, 2001a) reports the total world electricity generation was 13,674 TWh in 1998 and increased by 2.6% to 14,028 TWh in 1999. The distribution of world electricity generation by the primary fuel types is shown in Figure 3-6.

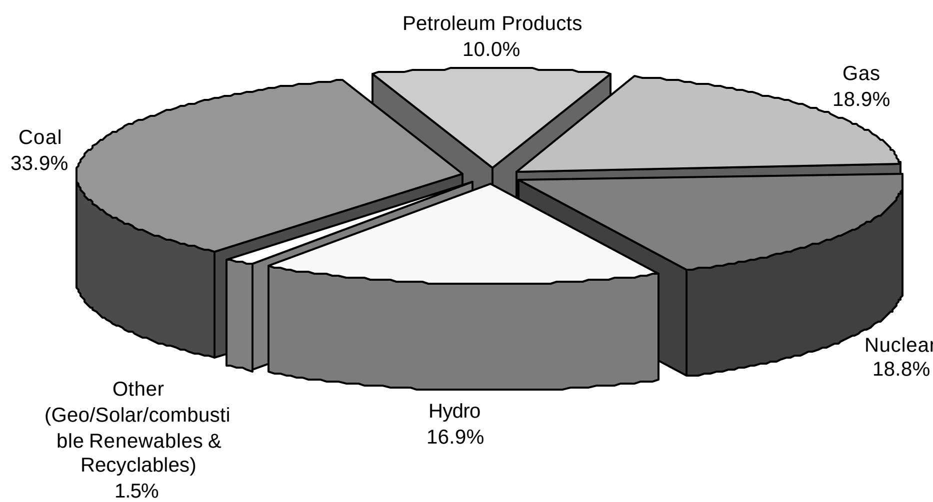
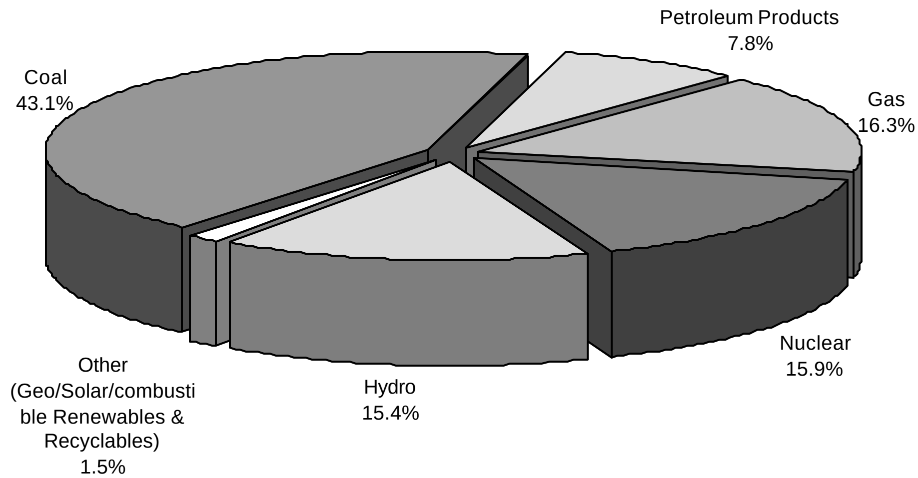


Figure 3-6 Current Distribution of GWh World Electricity Generation According to Fuel Type

It is evident that thermal generation of electricity by the burning of fossil fuels provides the majority of the world's electricity at 63% of the total GWh output, with coal making up the greatest portion, at 33.9%, followed next by natural gas at 18.9% and oil at 10%.



Source: CIA World Fact Book, 2001

Figure 3-7 Current Distribution of APEC GWh Electricity Generation According to Fuel Type

APEC economies collectively generate about 61% of the world's electricity. The 1999 distribution of electricity generation according to fuel type in the APEC region (Figure 3-7) is similar to that found globally, with the exception of coal use, which represents 43.1% of the fuel for electricity generation in APEC economies compared to 33.9% globally (CIA, 2001). This is partly due to the large use of coal as a primary energy source in the United States, which produces about 1881 TWh from coal, and in the People's Republic of China, which produces about 860 TWh from coal.

Globally and in the APEC region, a very small percentage (1.5-1.6%) of the electricity is generated from non-hydroelectric renewable electricity generation (here referred to as "other") sources in Figures 3-7 and 3-8.

Very limited data are available on the input energy used for electricity generation in the APEC region. Using APEC (2001) data for 1999 for the petajoules of fossil fuels consumed for electricity generation, which appears to be more complete than data for 1998, together with data on the electricity generated using other energy sources, an input energy distribution was developed. Input energy used to generate electricity from hydro, nuclear, geothermal and biomass energy sources was calculated using nominal conversion efficiencies indicated in APEC Energy Statistics 1998 (APEC, 2000). The results (Table 3-5) show that coal contributes 47.3%, natural gas 21.0% and oil 6.3% of the total input energy used in the APEC region for electricity generation. Nuclear energy is the next largest input energy source for electricity, at 18.1%, followed by hydroelectric power at 5.4%. The contribution of the energy sources varies widely between APEC economies depending on the energy mix used.

Table 3-5 Input Energy Used in APEC Economies for Electricity Generation in 1999

APEC Economy	Oil		Natural gas		Coal		Nuclear		Hydro		Geothermal		Other		Total Input
	PJ	%	PJ	%	PJ	%	PJ	%	PJ	%	PJ	%	PJ	%	PJ
Australia	20	1.1	172	9.1	1647	86.7		0.0	60	3.2		0.0	0	0.0	1,899
Brunei Darussalam	0	0.0	51	100.0	0	0.0		0.0		0.0		0.0		0.0	51
Canada	123	3.9	193	6.1	868	27.3	756	23.7	1,244	39.1		0.0	1	0.0	3,185
Chile	39	14.8	48	18.3	120	45.6		0.0	56	21.3		0.0		0.0	263
PR China	651	5.0	77	0.6	11,415	87.5	163	1.3	734	5.6		0.0		0.0	13,040
Hong Kong, China	2	0.8	93	38.3	148	60.9		0.0		0.0		0.0		0.0	243
Indonesia	181	18.7	305	31.6	303	31.4		0.0	37	3.8	140	14.5		0.0	966
Japan	1,396	15.6	1,842	20.6	1,713	19.2	3,466	38.8	318	3.6	124	1.4	72	0.8	8,932
Republic of Korea	153	6.6	234	10.1	782	33.8	1,124	48.6	22	0.9		0.0		0.0	2,315
Malaysia	54	9.3	445	76.4	56	9.6		0.0	27	4.7		0.0		0.0	582
Mexico	905	50.7	273	15.3	179	10.0	109	6.1	118	6.6	202	11.3	0	0.0	1,786
New Zealand	0	0.0	86	31.9	12	4.5		0.0	84	31.0	84	31.1	4	1.5	269
Papua New Guinea	8	46.2	6	34.7	0	0.0		0.0	3	19.1		0.0		0.0	17
Peru	35	35.6	11	11.2	0	0.0		0.0	52	53.2		0.0		0.0	98
Philippines	136	21.2	3	0.5	93	14.5		0.0	28	4.4	381	59.4		0.0	642
Russia	0	0.0	7,376	64.0	2,231	19.4	1,331	11.6	579	5.0	1	0.0		0.0	11,518
Singapore	0	0.0	39	100.0	0	0.0		0.0		0.0		0.0		0.0	39
Chinese Taipei	265	17.2	119	7.7	704	45.7	419	27.2	32	2.1		0.0		0.0	1,539
Thailand	154	18.2	509	60.3	169	20.0		0.0	13	1.5	0	0.0		0.0	845
United States	1,166	3.2	5,830	16.1	19,527	53.9	7,909	21.9	1,128	3.1	605	1.7	31	0.1	36,197
Vietnam	47	27.6	31	18.2	43	25.2		0.0	50	29.1		0.0		0.0	171
Total	5,335	6.3	17,742	21.0	40012	47.3	15,323	18.1	4,585	5.4	1,539	1.8	108	0.1	84,644

Assumed efficiencies for non-fossil energy use: Nuclear: 33%, Hydro: 100%, Geothermal: 10% and Other: 100%.
Source: After APEC, 2001.

A notable difference in fuel-use for electricity generation relative to the world average include a higher proportion of oil and gas use in developing Asia. Appendix B summarises existing data for electricity generation in APEC economies by fuel type. Examples of economies with high reliance on oil and gas for electricity generation are Singapore and Papua New Guinea, which use oil to produce over 50% of their electricity, and Brunei, Malaysia, and Thailand, which use natural gas for over 50% of their individual electricity generating needs. However, the collective power generation in these developing economies is comparatively small relative to the total in the APEC region, because of the contribution of other larger economies. The smaller economies account for only 7% of the total APEC electricity generated by fossil fuels.

The APEC region accounts for 42% of the world's population and 61% of the world's electricity generation. The generation of electricity varies substantially on a per capita basis among APEC economies, depending on the extent of development industry and electricity infrastructure. As shown in Figure 3-8, the electricity generation in kWh per capita varies from a very low level of about 300 kWh/person for some developing Asian nations (Indonesia, Papua New Guinea, Philippines, and Vietnam) to a high level for some industrialized economies, such as Canada (17,084 kWh/person) and the United States (13,130 kWh/person) (U.S. CIA, 2001).

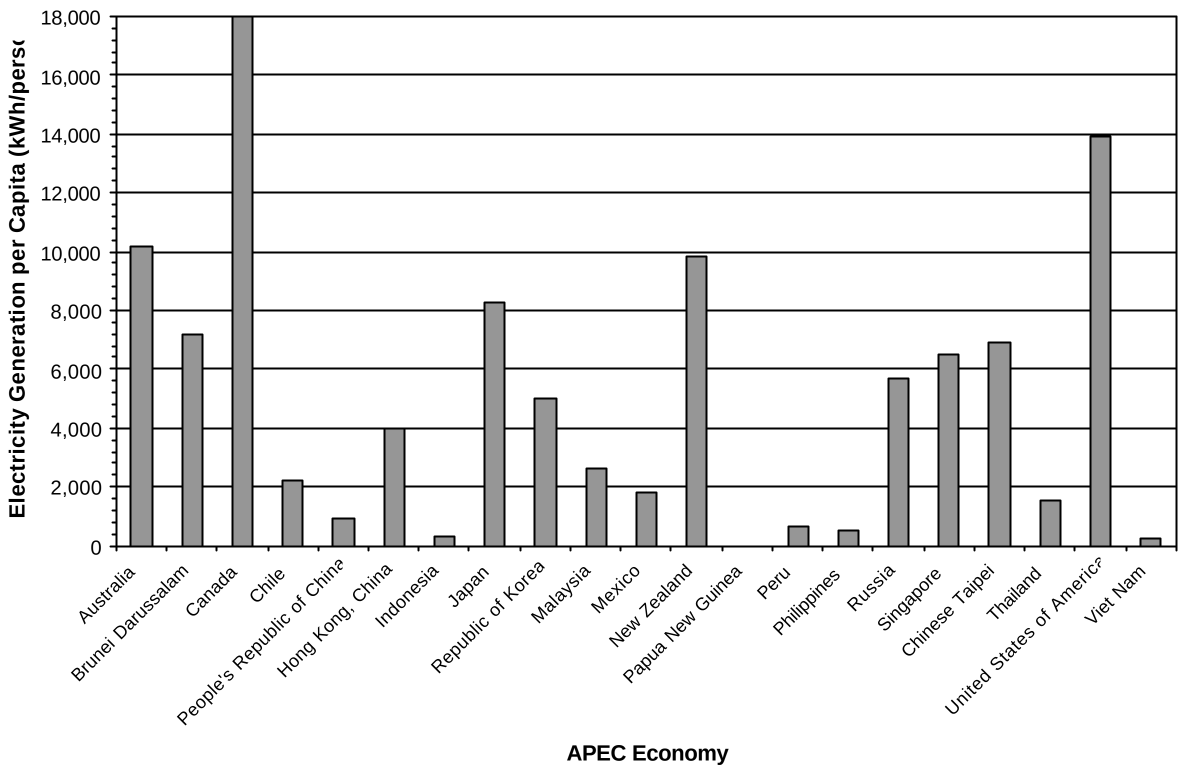


Figure 3-8 Distribution of Electricity Generation per Capita in APEC Economies in 1998-2000

The age distribution of existing power plants for different fossil fuels, as shown in Figure 3-9 from the UDI database updated to November, 2000, suggests the long-term changes that have occurred in the technology used for electricity generation in the APEC region. For both coal and oil fuel sources, the largest capacity of electricity is generated from plants that are between 16 and 30 years old. Within the last 15 years, a shift has occurred from oil to gas as a primary fuel source. Whereas oil-fired power plants represent 26.4% of the plants built 16-30 years ago, this slips to 12.7% of the power plants constructed in the last 15 years. In fact, over 51% of the operating oil-fired facilities were constructed between 16 and 30 years ago. The biggest contributors to this change are the United States and Japan. Of all the oil-fired facilities in the USA, only 7% have been established in the last 15 years, while in Japan, they represent 9%.

Meanwhile gas-fired power plants have increased from a 23.4% share of all fossil-fuelled power plants 16-30 years ago to 35.7% within the last 15 years. The power capacity in gas-fired facilities built in the last 15 years versus the previous 15 years is greater for all APEC economies except Canada, Mexico, and Russia. However, it should be noted that a majority of the fossil-fuelled power generating facilities listed in the worldwide power plant database for Russia are lacking information regarding the year of startup.

Overall, there has been a decrease in the total capacity of fossil-fuel fired electricity generating plants within the last 15 years in comparison to the previous 15 years. The total capacity for fossil-fuelled power generating facilities built 15 to 30 years ago is 481 GW, versus 425 GW of capacity available for facilities less than 15 years old.

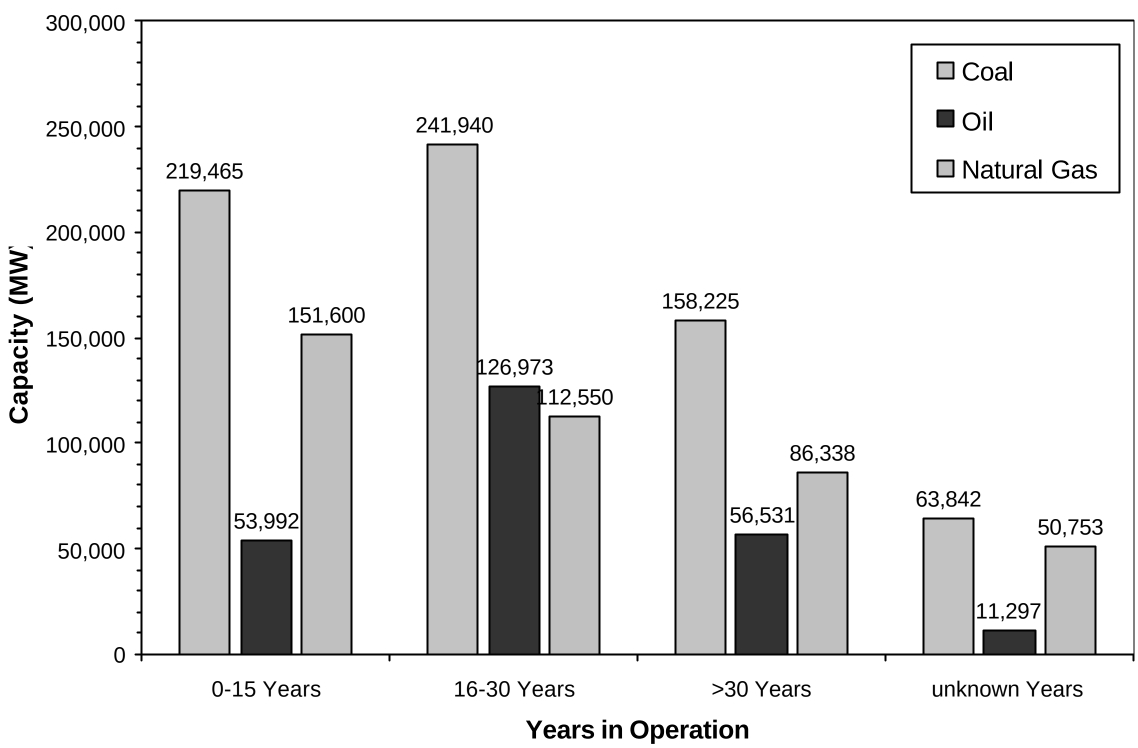


Figure 3-9 Age Distribution of Operating Fossil-Fuelled Power Plants in the APEC Region in 1999-2000

3.5 EXISTING POWER GENERATION TECHNOLOGIES AND THEIR PERFORMANCE CHARACTERISTICS

3.5.1 Fossil Fuel Power Generation

As discussed in Section 3.3, fossil fuels comprise by far the largest share of power generation in APEC economies. Table 3-6 summarises the significant technologies presently employed by APEC economies to generate electricity from coal, natural gas, and oil. Technologies in this table are listed in ascending order of net cycle efficiency on a lower heating value (LHV) basis. The energy technologies referred to in Table 3-6 are described in this section, and means of improving existing systems to achieve efficiencies towards the upper end of the indicated efficiency ranges are discussed in Chapter 4.

Some technologies, such as AFBC, produce measurable amounts of nitrous oxide (N_2O) or methane (CH_4). However, for all practical purposes, it is CO_2, which is emitted in proportion to cycle efficiency for a given fuel carbon content, that is the dominant component of total greenhouse gas (GHG) emissions. While any particular technology involves a range of cycle efficiencies depending on plant design factors such as fuel type, fuel quality, equipment age, and steam cycle features, only the nominal or typical range of efficiency for a properly designed and operated unit is listed.

Table 3-6 Types and Typical Full-Load Efficiencies of Fossil Fuel Power Generation Technologies

	Category	Technology	Net Efficiency* (%)
Coal	Stoker/Cyclone Steam Cycle	Stoker-Fired Steam (underfeed, overfeed, spreader)	20-32
		Cyclone Steam	32-35
	Pulverized Coal Steam Cycle	Subcritical	36-39
		Supercritical and ultra supercritical	40-46
	Fluidized Bed Steam Cycle	Circulating Fluidized Bed (atmospheric)	34-40
		Atmospheric Bubbling Fluidized Bed	34-40
		Pressurised Fluidized Bed Combustion	39-41
		Pressurised Fluidized Bed/Combined Cycle	42-45
	Gasification/Gas Turbine Combined Cycle	Moving Bed IGCC	40-43
		Pressurised Fluid Bed IGCC	40-44
		Entrained Flow IGCC	42-46
	Combined Heat & Power	Cogeneration	50-85
Gas/Oil	Internal Combustion	Reciprocating Engine	30-34
	Steam Boiler	Subcritical	36-38
		Supercritical	40-42
	Gas Turbine	Gas Turbine Simple Cycle (GTSC) or Peaking Units	24-37
		Gas Turbine Combined Cycle (GTCC)	53-60
	Combined Heat & Power	Depends on design and the efficiency of heat use.	65-85%

Sources: Singer, 1991; Smith, 1999; Stultz and Kitto, 1992; IEA, 1996; IEA, 1997b; Greth and Susta, 2001; and Boeuf and Spemann, 2001.

* Typical full-load efficiency, based on fuel lower (net) heating value.

3.5.1.1 *Coal-Fired Technologies*

The most common coal-fired technologies utilised in APEC economies have been grouped into five categories, as shown in Table 3-6.

Stoker technologies evolved from the era of manually fired boilers. Stokers combust "course" (e.g., 30 mm size) or "crushed" (e.g., 6 mm size) coal on a grate, with some combustion air fed from below the grate. Cyclone boilers, developed later than stokers, have specially-designed burners to utilise crushed coal. Both types of equipment are utilised in conventional steam turbine cycles, and can fire coals that are not well suited for pulverisation, usually due to low ash fusion (melting) temperatures. These technologies have been employed in some applications to save fuel system capital and operating and maintenance costs at the expense of efficiency (fuel cost).

Pulverized coal systems are by far the most widespread coal-fired technology in APEC economies. With these systems, crushed coal is pulverized to 70-80% (by mass) sized 74 microns (0.074 mm) or smaller and fed to burners entrained with hot air. These systems have the added capital and operating and maintenance costs for the pulverizer system, but with the advantage of higher combustion efficiencies. Pulverized coal boilers are utilised in conventional steam cycles as well as more advanced supercritical steam cycles. While pulverized coal is not applicable to gas turbine combined cycles, it is suited to cogeneration applications if the waste heat can be utilised for process or heating needs. Pulverized coal firing systems are adaptable to a wide range of coal quality, but still are less fuel flexible than stoker or fluidized bed technologies.

Fluidized bed combustion technologies are applicable to subcritical or supercritical steam cycles, as well as cogeneration. Bubbling and circulating fluidized bed technologies typically combust crushed coal in a suspended bed (with sand) firing at atmospheric pressures. Pressurised fluidized bed combustion (PFBC) is an advanced bubbling bed technology combusting coal at 10-20 atmospheres pressure, with the unique advantage of enabling use of gas turbines for higher cycle efficiency. While fluidized bed combustion is generally higher capital cost relative to pulverized systems, it has the following distinct advantages:

- Allows use of low grade coals containing up to 50% moisture, up to 70% ash, or low volatiles (anthracite).
- Operation with low combustion temperatures, resulting in low NO_x and enabling use of low ash softening (melting) temperature coals.
- Injecting limestone or dolomite into the fluidized bed removes sulphur as calcium sulphate, and avoids expensive SO_2 flue gas scrubbers.

Coal gasification is well proven technology and continues to be further developed for advanced energy applications. With this technology, coal is heated in the presence of steam and a low oxygen environment to produce a gaseous fuel. The three main types are:

- Moving bed gasifiers use course coal, prefer low rank coal, and operate at low temperature.
- Pressurised fluidized gasifiers use crushed coal, prefer low rank coal, and operate at moderate temperatures.
- Entrained flow gasifiers use pulverized coal, any rank coal, and operate at higher temperatures for improved cycle efficiency.

The gasified coal fuel is cleaned and suitable for application in a gas turbine combined cycle power plant. Integrated coal gasification combined cycle (IGCC) power plants are largely still in demonstration stages in APEC economies, but have the highest efficiency and hence lowest CO_2 emissions of any technology, except combined heat and power.

3.5.1.2 Gas-Fired and Oil-Fired Technologies

In general, the same energy conversion technologies are applicable to both natural gas and fuel oil, which is why these fuels are summarised together in Table 3-6. Light oil (diesel fuel/No. 2 oil being the most common) is directly usable with all technologies shown in the Table. Heavier fuel oils, such as commonly-used No. 6 oil, require heating to achieve the proper viscosity for use. Natural gas always results in lower levels of air emissions compared to oil, including GHG emissions due to the lower fuel carbon content (reduced CO_2).

Internal combustion (IC) engines are well-proven, reliable equipment commonly used for low capacity (e.g., under 100 MW) power generation with gas or oil and are well suited for remote locations such islands or rural areas, or even for peaking power applications. Conventional subcritical and advanced supercritical steam boiler with steam turbine is the most common existing technology for large-scale gas and oil power plants in developed APEC economies. Power facilities utilitizing internal combustion engines or simple-cycle gas turbine design (GTSC) are more prevalent in developing APEC economies than in developed economies. For the analysis conducted in this study, the simple cycle (SC) category of power plants includes both internal combustion engine and gas turbine equipment.

Gas turbine combined cycle (GTCC) plants have become the preferred technology for new plants in recent years because of inherent cycle efficiency benefits, reasonable capital costs, and demonstrated reliability. In this type of system, natural gas is combusted in gas turbines, and then the high temperature exhaust is run through a heat recovery steam generator (HRSG). Thus electricity is produced both from the gas turbine shaft as well as a steam turbine.

Combined heat and power is more commonly used with gas and oil combustion technologies as compared to coal. Internal combustion engines, steam boilers, and gas turbines are all applicable to cogeneration of electricity and steam. Common sources of use of waste heat include district heating/cooling and industrial processes. While combined heat and power is clearly the most efficient technology, the biggest challenge is locating power production near a demand for waste heat, and matching the simultaneous demands for electricity and heat throughout diurnal and seasonal variations.

3.5.2 Hydroelectric Power

Hydroelectric power is the second largest source of electricity generation in APEC economies as shown in Section 3.3. The use of dams and water turbines is applicable to a wide range of plant size, from 10 MW to over 10,000 MW capacity for individual power stations. International reporting practices and common understanding for hydroelectric power is as a zero CO_2 emission technology and a renewable resource.

While there is no definitive scientific evidence at present to warrant changes in hydroelectricity as a zero CO_2 technology, the issue of net CO_2 emissions from hydroelectric dams is a growing area of research. Publications mostly from the World Commission on Dams are based on scientific research conducted for boreal (northern) and tropical regions on life cycle emissions of CO_2 and methane (CH_4). The published research indicates that tropical regions have greater potential for net increases in CO_2 emissions, which is an issue APEC economies may want to consider in power generation strategies. The basic scientific questions involve net CO_2 and CH_4 emissions from flooded vegetation as compared to pre-existing conditions.

3.5.3 Nuclear Power

Nuclear power is a zero CO_2 emission technology based on converting mass to energy via nuclear fission, following Albert Einstein's famous equation: $E = mc^2$ where E = energy, m = particle mass, and c = speed of light. Steam is used as the nuclear reactor coolant and electricity is produced using steam turbine technology. Plant sizes tend to be large ranging from several hundred to several thousand MW capacities for individual power stations.

Because of concerns over radioactive waste disposal and consequences of failures, new nuclear power installations have drastically declined in APEC economies as a whole over the past two decades. However, as shown in Section 3.5 some APEC economies are planning new nuclear power facilities (e.g., Korea, Japan) over the next 5-20 years, that will result in lower CO_2 emissions than if the energy was provide by fossil fuels.

3.5.4 Biomass, Waste Gas, and Solid Waste

Biomass, waste gas, and solid waste fuels for power production make up only a very small share of electricity production in APEC economies.

Biomass combustion includes a range of agricultural waste products in APEC economies. Stoker boiler, steam cycle power plants are typically employed for biomass. In developed APEC economies, atmospheric fluidized bed technologies are employed in some cases. Stoker and fluidized bed technologies are the same as described for coal in Section 3.4.1, with the only significant difference being the fuel processing system upstream of the boiler. As introduced in Section 3.6, CO_2 from biomass is presently not counted as a net CO_2 emission if derived from a sustainable forest, only the N_2O and CH_4 emissions.

Waste fuel gases, as described in this report, refer to combustible gases from digester or sewers, landfills, refineries, mines, and blast furnaces. Internal combustion engines, steam boilers, and gas turbine combustion technologies (described in Section 3.4.1) are also used to recover energy from waste fuel gases. It is most often that these fuel gases are used in relatively small capacity, kW-scale plants.

Solid waste includes material such as municipal refuse, tires, and wastewater sludge. The same technologies as described for biomass are utilised for solid waste.

3.5.5 Other "Zero" GHG Emission Technologies

Geothermal steam, solar thermal, solar photovoltaic, wind, and tidal power generation are all employed to some degree in various APEC economies.

Geothermal steam uses the heat of the earth's interior, extracted as either dry steam or hot water, to generate steam for low pressure, low temperature steam turbines. Key design and operating issues are purity and chemical composition of the extracted steam or hot water, and the reliability of the power plant. The United States, the Philippines, and Indonesia amongst other APEC economies have geothermal power.

Solar thermal power technology includes various options on solar collectors to transfer heat to a working fluid. During the late 1980's, 400 MW of solar thermal power plants were constructed in the south-western United States. Based on Israeli technology, these plants utilised solar trough collectors with steam heat exchangers, steam turbines, and gas-fired boilers as back up or co-firing to match output with demand.

Solar photovoltaic systems have grown in interest in recent years. These technologies directly convert solar energy into electricity. Photovoltaics are presently used mostly for small kilowatt capacity power generation, and fit into the distributed energy category.

Wind turbines and tidal power are other small sources of power existing in APEC economies. These technologies convert wind and tidal energy into electricity using wind turbines and specialised tidal water turbines, respectively.

3.5.6 Survey Responses for Existing Power Generation Technologies

Six economies provided details of their existing power generation technologies and the completed survey questionnaires are included in Appendix C. Not all participants provided exactly the same description information, so some technology types were inferred from the reported plant efficiency. Respondents to the survey provided data for state-owned and privately owned power facilities. Survey responses for the megawatts of existing generating capacity for each type of fuel and technology are summarized in Table B-7 in Appendix B.

Figure 3-10 illustrates the variation in coal-fired technologies in use by the survey respondents. Japan did not define the technologies and grouped their plants into category based on the efficiency, so all of their moderate and high efficiency coal-fired power was assumed to be subcritical and supercritical steam turbine plants, respectively. While no fluidized bed or gasification technologies were specified, some of Japan's high-efficiency power includes some of these late generation technologies. As is typical for APEC economies as a whole, pulverized coal, subcritical steam turbine power plants dominate the mix of coal-fired power.

Figure 3-11 illustrates the variation in gas-fired technologies in use by the six survey respondents. All moderate efficiency gas-fired power reported by Japan were considered to be subcritical steam turbine plants, however with efficiencies up to 40% this group of plants undoubtedly includes supercritical steam and older GTCC in the mix. Japanese high-efficiency power was reported at 49% average efficiency, which realistically could only be GTCC plants (or possibly combined heat and power). Peru, Mexico, and Philippines economies have little gas-fired power capacity. All of Hong Kong's gas-fired plants were identified as high-efficiency GTCC technology.

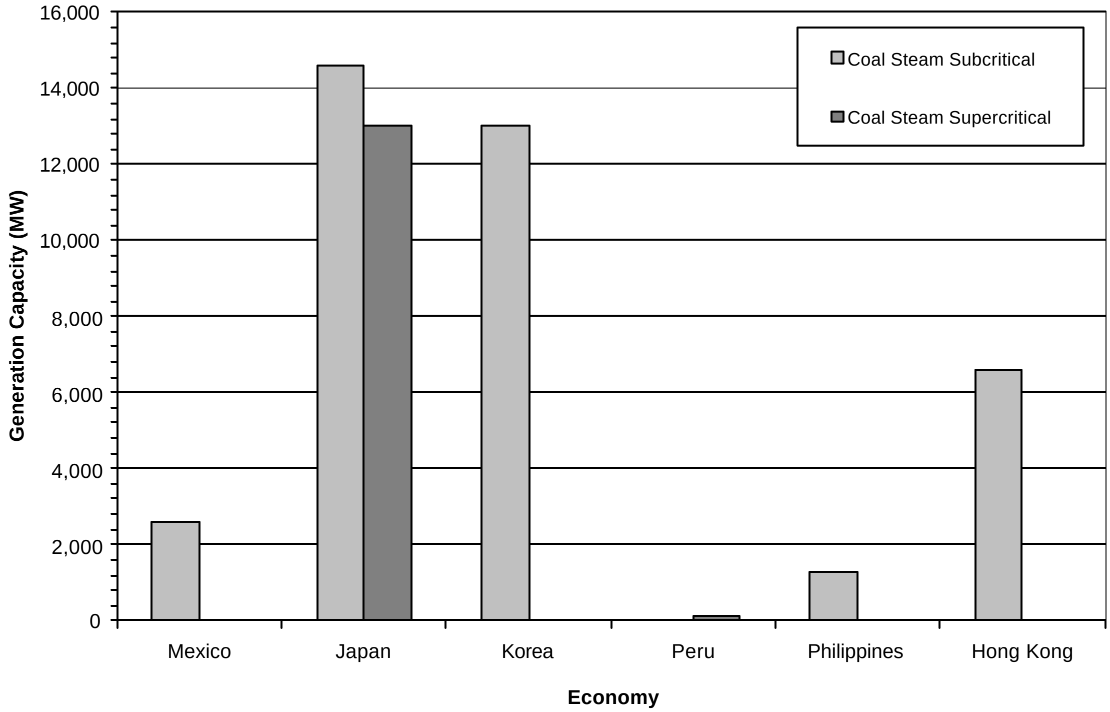


Figure 3-10 Coal Power Plant Capacity Based on Survey Results

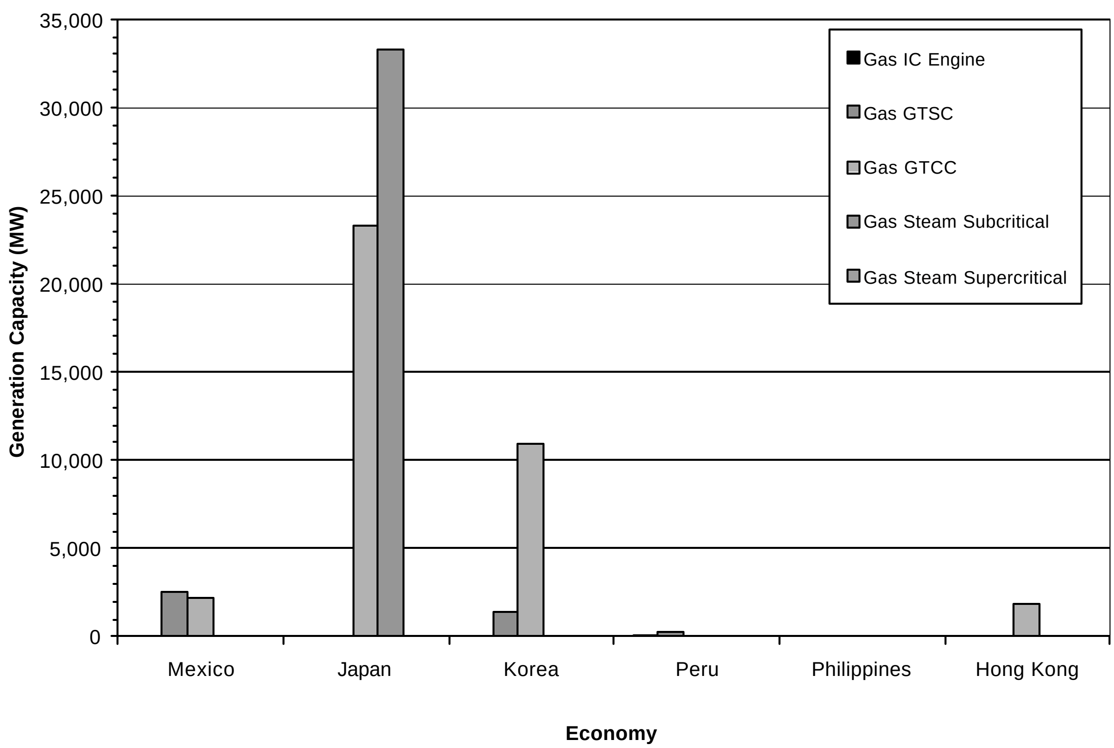


Figure 3-11 Gas Power Plant Capacity Based on Survey Results

Figure 3-12 illustrates the variation in oil-fired technologies in use by the survey respondents. All of Hong Kong's oil-fired capacity was identified as peaking power with very low GWh production. The Philippines oil-fired plants were fairly evenly distributed amongst the five categories of technologies as shown.

Japan reported an average efficiency of 36% for the moderate efficiency category, so this group is plotted as subcritical steam turbine technology. However with a range of plant efficiency from 28%-40%, the mix of oil-fired plants in this moderate category very likely includes GTSC, older GTCC, and supercritical steam turbine technologies. All of Japan's high efficiency (greater than 40%) oil-fired capacity is plotted as supercritical steam, but could include GTCC.

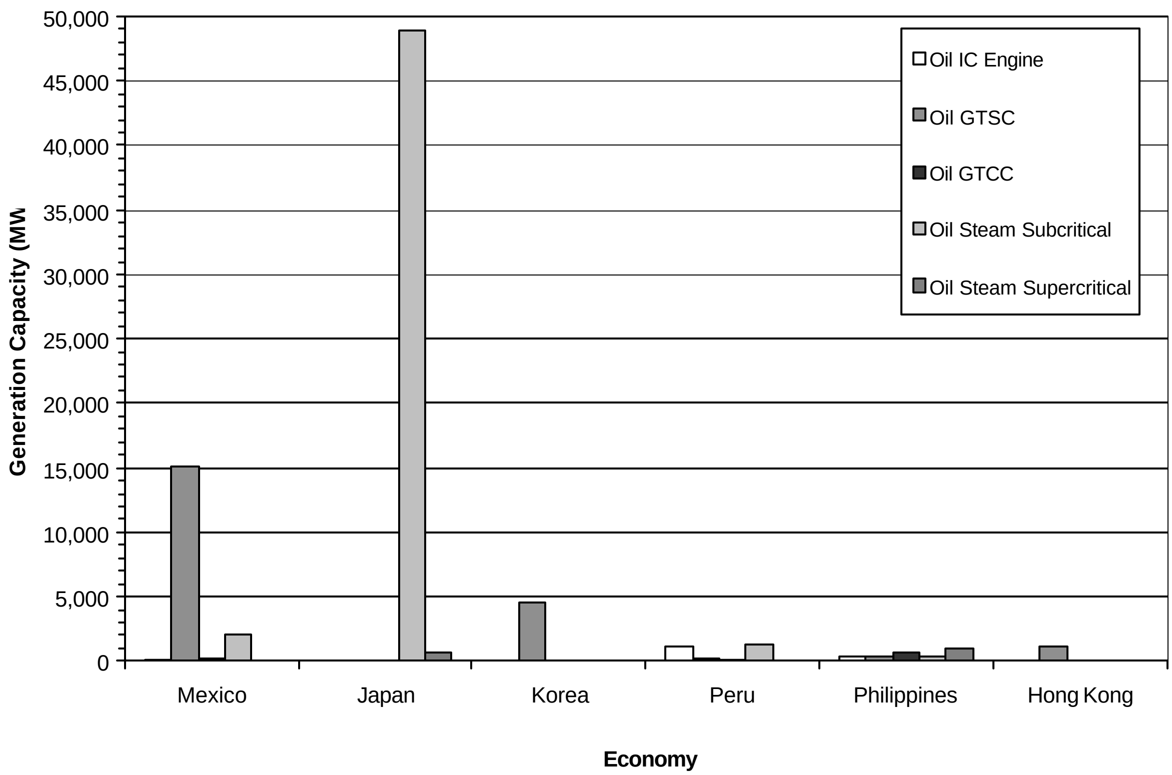


Figure 3-12 Oil Power Plant Capacity Based on Survey Results

Figure 3-13 shows the hydroelectric and nuclear facilities in use by the survey respondents. Peru, Philippines, and Hong Kong identified no nuclear power. Nuclear power was identified as the largest capacity for Korea, while Japan's survey indicated nuclear second only to oil-fired plants.

Figure 3-14 shows the wind, geothermal, and biomass facilities in use by the survey respondents. Philippines reported over 1,200 MW of geothermal power facilities, while Mexico identified over 800 MW as one total for wind and geothermal combined. Only Peru indicated biomass power, however, biomass power facilities are most often owned and operated by private producers which did not provide data.

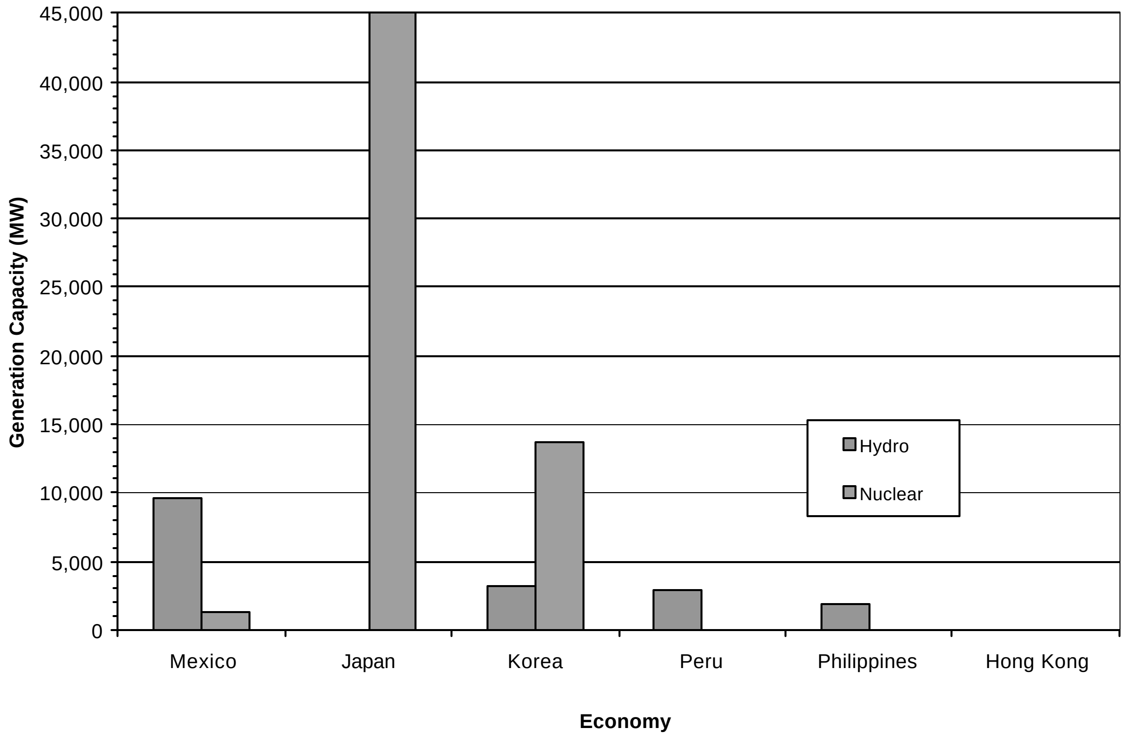


Figure 3-13 Hydro and Nuclear Power Plant Capacity Based on Survey Results

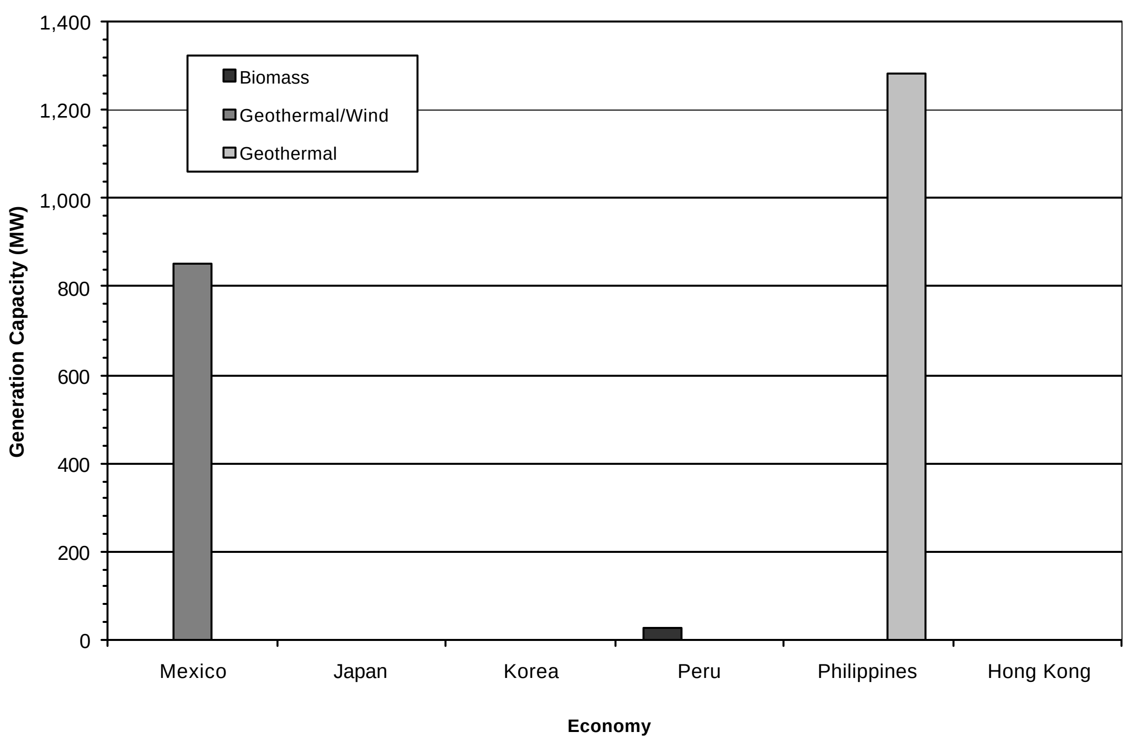


Figure 3-14 Other Power Plant Capacity Based on Survey Results

3.5.7 Electricity Generation Technologies in UDI Database for APEC Economies

The UDI database obtained for this study provides information for most state and private facilities on the type of fuel and the type of energy technology being used. All of the facility data for the APEC economies were analyzed to determine the total existing generating capacity associated with each of the key generic types of energy technology for oil, natural gas and coal. The resulting data provided the basis for analysis for the potential carbon dioxide emission reductions that could be achieved by implementing various mitigation options and is more comprehensive than the limited data set obtained from the survey.

Table 3-7 tabulates the megawatts of capacity for each fossil fuel and combined other energy sources (hydro, nuclear, geothermal, and renewable energy) and indicates the distribution by type of technology in each economy for oil, natural gas and coal fired facilities. The total capacity stated for each economy includes all facilities recorded in the UDI database to the cut-off date for the dataset of November, 2000.

The dominant technology for coal-fired facilities is pulverized coal firing with a subcritical boiler. High efficiency supercritical boiler technology with pulverized coal firing is used at a significant share of the facilities in Japan, Korea, Russia and the United States.

Many economies are reported to have a significant percentage of existing (public and privately owned) gas-fired and oil-fired capacity as combined heat and power facilities, which will yield a higher energy efficiency than possible with conventional plants. Many economies however, report a low level, or no cogeneration systems, and opportunities would therefore exist for greater use of this higher efficiency technology. Many economies report using either simple cycle gas turbine systems or subcritical steam turbines, while only a few utilize supercritical gas or oil fired boilers/steam turbines.

Table 3-7 Distribution of Existing Capacity by Fuel and Type of Energy Technology for APEC Economies as of November, 2000

Technology	Australia	Brunei Darussalam	Canada	Chile	PR China	Hong Kong, China	Indo-nesia	Japan	Korea	Malaysia	Mexico	New Zealand	Papua New Guinea	Peru	Philippines	Russia	Singapore	Chinese Taipei	Thailand	U.S.	Viet Nam	Total APEC
Total Capacity for All Energy Sources (MW)	44,526	818	110,601	9,700	231,038	11,041	30,041	256,268	53,057	17,209	39,352	9,269	780	4,863	17,385	217,256	7,115	34,307	23,513	832,875	6,391	1,957,404
Gas-fired Capacity (MW)	5,986	806	9,991	1,713	1,231	2,046	5,690	52,858	11,910	7,837	4,872	1,592	121	222	683	87,946	1,299	4,279	12,154	188,343	898	402,476
Gas-fired (% of Total MW)	13.4	98.5	9.0	17.7	0.5	18.5	18.9	20.6	22.4	45.5	12.4	17.2	15.5	4.6	3.9	40.5	18.3	12.5	51.7	22.6	14.1	20.6
Combined Cycle or CHP (% gas)	17.7	0.0	22.7	98.6	40.4	100.0	69.3	41.9	59.2	45.6	48.3	61.8	0.0	0.0	48.3	0.4	3.8	82.6	58.8	25.0	0.0	26.4
Simple Cycle* (% gas)	41.8	100.0	24.3	0.3	58.1	0.0	30.4	1.8	5.9	49.8	29.6	0.4	100.0	94.3	51.7	2.3	0.0	1.4	8.5	24.8	100.0	16.6
Steam Turbine - Subcritical (% gas)	40.5	0.0	53.1	1.1	1.5	0.0	0.3	14.0	34.9	4.6	22.0	37.8	0.0	5.7	0.0	76.9	96.2	16.0	32.8	37.1	0.0	40.9
Steam Turbine - Supercritical (% gas)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	42.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	20.3	0.0	0.0	0.0	13.1	0.0	16.1
Oil-fired Capacity (MW)	2,733	12	4,684	1,304	13,767	2,382	9,467	71,667	6,298	3,585	17,850	433	438	1,719	7,862	11,706	5,331	7,970	1,142	79,202	1,506	251,058
Oil-fired (% of Total MW)	6.1	1.5	4.2	13.4	6.0	21.6	31.5	28.0	11.9	20.8	45.4	4.7	56.1	35.3	45.2	5.4	74.9	23.2	4.9	9.5	23.6	12.8
Combined Cycle or Combined Heat & Power (% oil)	1.0	0.0	3.3	8.4	21.7	0.0	20.9	4.3	29.9	20.7	2.0	3.7	0.0	1.8	21.9	56.7	11.4	20.2	14.5	4.9	3.4	10.4
Simple Cycle* (% oil)	77.3	100.0	29.3	74.7	43.0	55.1	51.8	4.8	27.2	37.3	13.1	96.3	69.1	83.7	52.4	2.8	10.4	28.2	16.6	42.1	41.6	27.5
Steam Turbine - Subcritical (% oil)	21.6	0.0	67.3	16.9	35.4	44.9	27.2	52.7	42.9	42.0	84.9	0.0	30.9	14.6	25.7	26.8	78.2	51.6	68.9	52.3	55.0	50.4
Steam Turbine - Supercritical (% oil)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	38.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.7	0.0	0.0	0.0	0.7	0.0	11.8
Coal-fired Capacity (MW)	27,057	0	17,818	1,947	160,413	6,610	7,197	29,549	13,900	1,700	2,600	1,021	0	270	4,258	50,782	0	9,218	3,467	333,528	693	672,029
Coal-fired (% of Total MW)	60.8	0.0	16.1	20.1	69.4	59.9	24.0	11.5	26.2	9.9	6.6	11.0	0.0	5.6	24.5	23.4	0.0	26.9	14.7	40.0	10.8	34.3
Stoker+Cyclone (% coal)	0.2	0.0	0.0	2.8	0.7	0.0	1.0	0.0	0.2	0.0	0.0	0.0	0.0	0.0	0.0	6.3	0.0	0.0	0.0	8.7	6.9	5.0
Pulverized Coal Subcritical (% coal)	99.8	0.0	99.1	93.7	95.4	100.0	99.0	34.1	37.7	100.0	100.0	99.2	0.0	100.0	100.0	78.3	0.0	100.0	80.2	65.6	93.1	75.8
Pulverized Coal Supercritical (% coal)	0.0	0.0	0.0	0.0	3.3	0.0	0.0	62.9	58.5	0.0	0.0	0.0	0.0	0.0	0.0	15.5	0.0	0.0	0.0	24.2	0.0	17.9
Fluidized Bed (% coal)	0.0	0.0	0.9	3.5	0.6	0.0	0.0	2.9	3.7	0.0	0.0	0.8	0.0	0.0	0.0	0.0	0.0	0.0	19.8	1.5	0.0	1.2
Non-Fossil Fuel Power Generation (MW)	8,751	0	78,108	4,735	55,627	4	7,686	102,193	20,951	4,087	14,029	6,222	221	2,652	4,581	66,822	485	12,840	6,750	231,802	3,294	631,841
Non-Fossil Fired** (% of Total MW)	19.7	0.0	70.6	48.8	24.1	0.0	25.6	39.9	39.5	23.8	35.7	67.1	28.4	54.5	26.4	30.8	6.8	37.4	28.7	27.8	51.5	32.3

* Gas turbine and some internal combustion engine systems.

** Balance of the total installed capacity not fuelled using natural gas, oil or coal.

Source: Data from UDI/McGraw-Hill Energy database updated to November, 2000.

3.6 PLANNED POWER GENERATION PROJECTS

In addition to the 1,957 GW of electricity generating capacity in APEC countries reported to November, 2000 in the UDI database, 42% of this current capacity, or 813 GW, is under construction or, according to trade journals and other public information, planned for installation within the next 20 years. The major fuel source for future power generating facilities is natural gas; with over 250 GW planned for the APEC economies within the next 20 years. This represents 30.8% of the planned and under construction power generation facilities, compared to the current portion of existing facilities that are gas-fired at 20.6% of the overall APEC capacity (Figure 3-15). Other trends in fuel sources observed from available information on planned future generating projects are the increase in the percentage of hydroelectric facilities and a decrease in the share of total new capacity that are coal-fired. Whereas hydroelectric power generating facilities currently account for 18.1% of the total APEC capacity, for facilities that are in the planning or construction stage, the hydroelectric portion is slightly higher at 23.4%. Meanwhile, the capacity of future coal-fired facilities accounts for 27.8% all currently planned facilities, versus its current share of the electricity generation market of 34.3%.

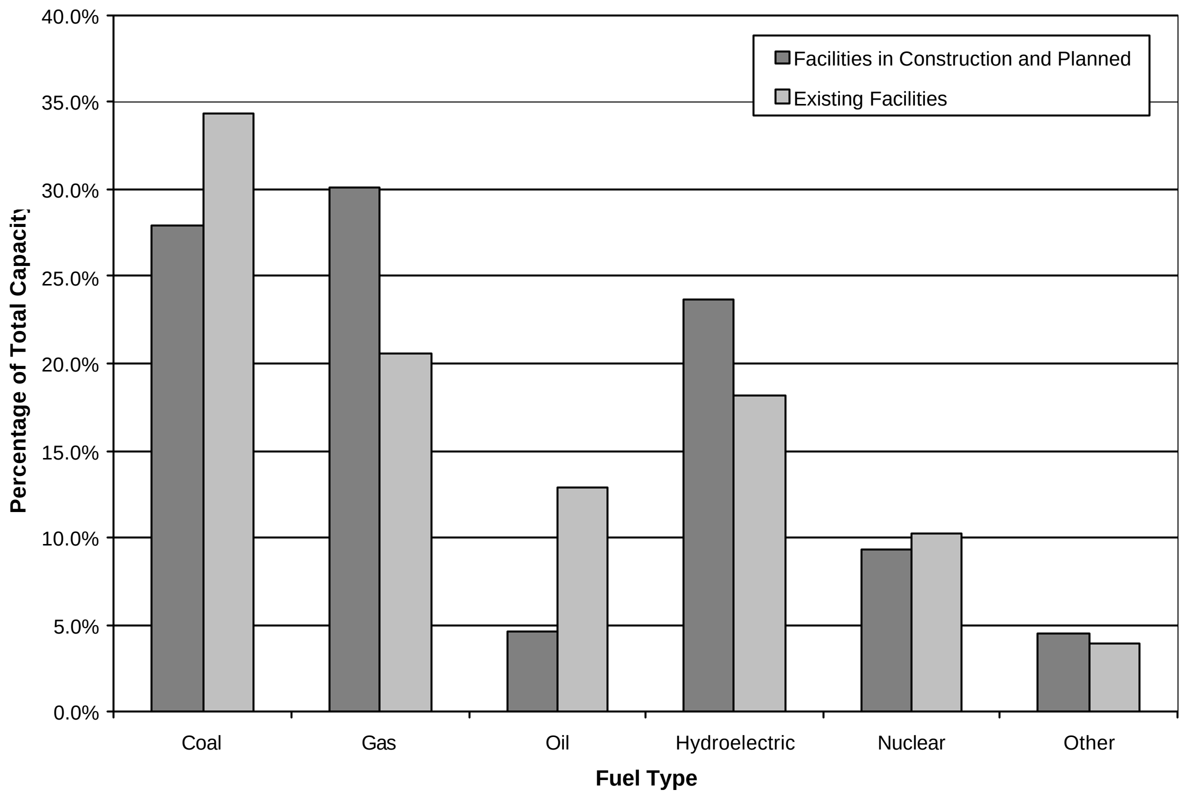


Figure 3-15 Percent of Existing and Future Electricity Generation Capacity by Fuel Type

In regards to future electricity generating trends by APEC economy, the largest increases in generating capacity are planned for China and the United States (Table 3-8), which are estimated to be planning and/or are constructing 297 GW and 199 GW of electrical generating capacity, respectively. In China, this is a 129% increase in generating capacity (Table 3-8). Other notable capacity increases include:

- Vietnam adding 12 GW to an existing 6.4 GW;
- Peru adding 5.0 GW to an existing 5.0 GW;
- Malaysia adding 12.0 GW to an existing 17.2 GW; and
- Thailand adding 18.4 GW to an existing 23.5 GW.

Of the two major contributors to the increase in electricity generating capacity, the United States will be fuelling the majority of its expansion projects (73.1%) by natural gas, while China will use coal-fired plants to produce 52.1% of its increased energy.

Table 3-8 Future Electricity Generating Facilities: Planned or Under Construction in the APEC Region

Economy	Existing Installed Capacity (GW)	Future Power Capacity (GW)			Capacity Increase (%)
		Under Construction	Planned*	Total	
Australia	44.5	3	5	8	18.9
Brunei Darussalam	0.8	0	0	0	0.0
Canada	110.6	2	17	19	17.2
Chile	9.7	1	3	4	41.3
People's Republic of China	231.0	92	206	298	128.8
Hong Kong, China	11.0	0	1	1	5.4
Indonesia	30.0	2	12	14	47.9
Japan	256.3	23	74	97	37.8
Republic of Korea	53.1	13	17	30	55.5
Malaysia	17.2	3	9	12	69.9
Mexico	39.4	5	17	22	57.3
New Zealand	9.3	0	0	0.2	1.9
Papua New Guinea	0.8	0	0	0	0.0
Peru	4.9	0	5	5	102.9
Philippines	17.4	2	6	8	49.9
Russia	217.3	25	18	43	19.7
Singapore	7.1	3	2	5	62.5
Chinese Taipei	34.3	10	8	18	52.3
Thailand	23.5	5	13	18	78.2
United States of America	832.9	64	135	199	23.9
Viet Nam	6.4	3	9	12	182.4
All APEC	1,957	256	557	813	41.5

Source: UDI/McGraw-Hill Energy database updated to November, 2000.

* Based on trade journals and other public announcements surveyed by UDI/McGraw-Hill Energy.

Figure 3-16 highlights the economies where the majority of new generating capacity is planned to be constructed in the APEC region. Although new capacity will be constructed in all the economies over the next 20 years, 82% is presently planned to be added in PR China, the United States, Japan, Russia and Korea, with the balance of 18% distributed to the remaining economies.

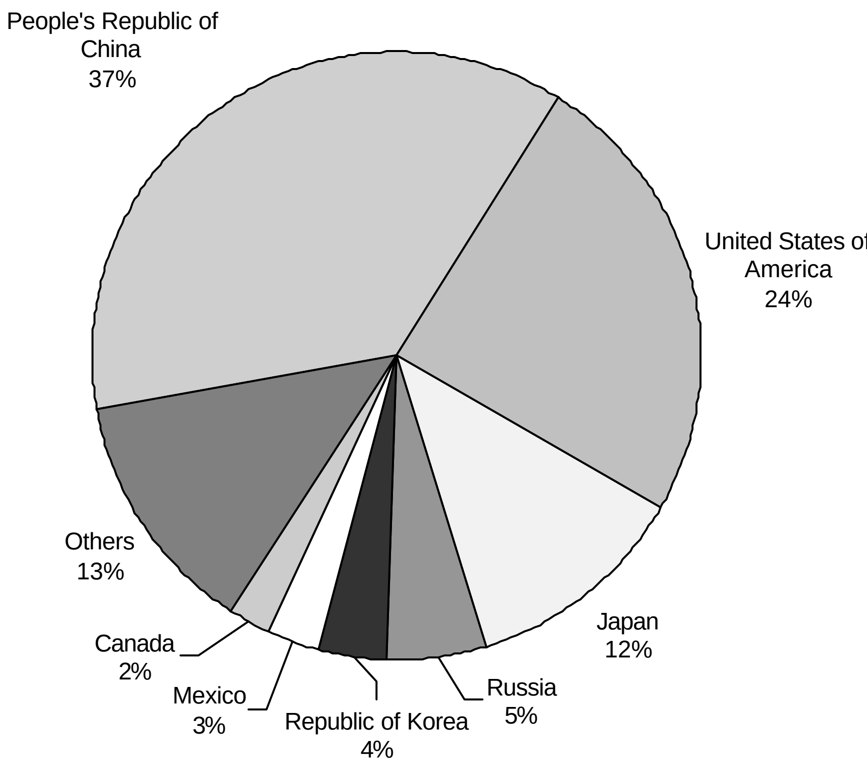
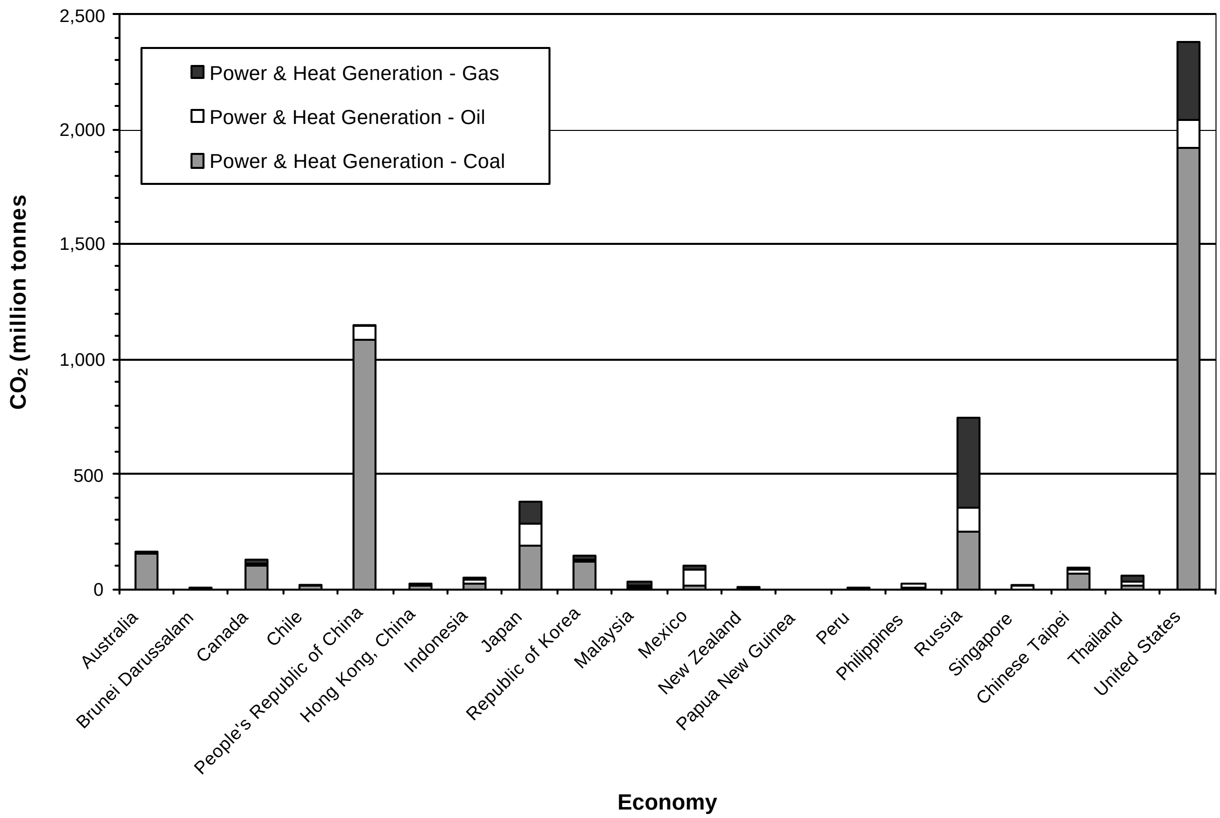


Figure 3-16 Distribution of Future Electricity Generating Facilities in the APEC Region

3.7 CO_2 EMISSION DATA FOR THE ELECTRICITY GENERATION SECTOR

APEC carbon dioxide emissions in 1998 from fossil fuel combustion in the electric power sector are shown in Figure 3-17. These emission values were determined by the International Energy Agency (IEA, 2000a) using the IPCC Tier 1 Sectoral Approach, which includes emissions arising when the fuel is combusted. The CO_2 emissions reported by the IEA are the combined total of emissions from public electricity and heat production and from unallocated autoproducers. This group of emission sources includes facilities that deliver electricity to a national grid, as well as those that provide electricity for a facility's own use. Public electricity and heat production is defined to include public electricity generation, public combined heat and power generation and public heat plants. Emissions from the unallocated autoproducer source category accounts for emissions from facilities that generate electricity and/or heat wholly or partly for their own use, as an activity that supports the primary activity of the facility. Public electricity and heat producers, and autoproducers may be publicly or privately owned, as defined for the IEA analysis. The reported CO_2 emissions are associated primarily with electricity generation, but also include some amount of emissions from heat generation, which are not disaggregated by the IEA.

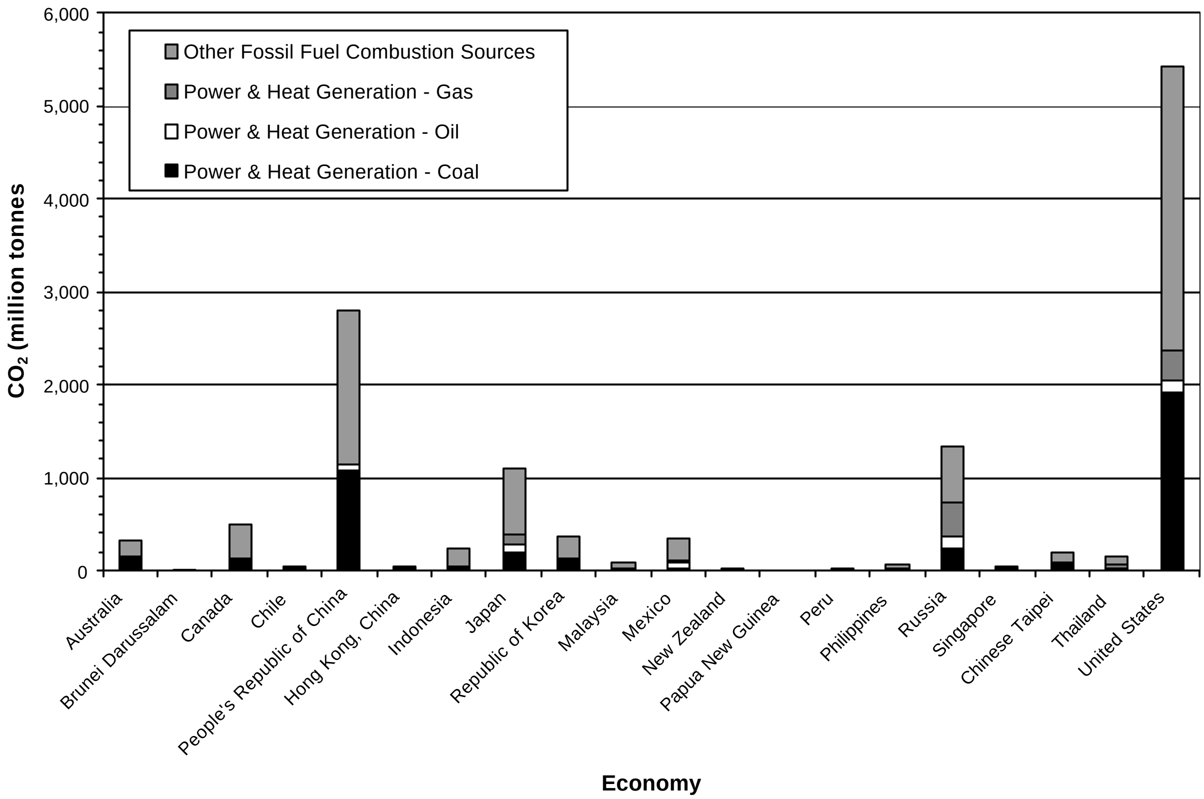


Source: IEA, 2000a

Figure 3-17 1998 CO_2 Emissions from Power Generation in APEC Economies

The United States, China, Russia, and Japan are the dominant economies in terms of carbon dioxide emissions from fuel combustion. CO_2 emissions from thermal electricity generation in the United States were approximately 2,375 million tonnes in 1998 and double those of PR China of 1,150 million tonnes, the next highest emitting economy. These data reflect the high energy consumption and high carbon in the fuel mix of electricity generation in the United States. While China has a very low per capita electricity generation, its high contribution to APEC CO_2 emissions reflects its population and dependence on coal-fired power. CO_2 emission data are listed for each APEC economy in Table B-5 in Appendix B.

To illustrate the relative importance of electricity generation to anthropogenic CO_2 emissions, Figure 3-18 compares APEC fossil power generation to other fuel combustion sources. Other combustion sources include large contributors such as vehicles and industry. As seen from the chart, electricity generation accounts for roughly one-third to one-half of all combustion sources of CO_2 emissions. This clearly defines the power sector as a key component of the total CO_2 emissions in APEC from fuel combustion, and important to any CO_2 reduction strategy.



Source: IEA, 2000a

Figure 3-18 1998 CO_2 Emissions from Fossil Fuel Combustion in APEC Countries

A key overall indicator of the impact of the efficiency of technologies is the tonnes of CO_2 emissions per gigawatt-hour of electricity generated, as shown in Figure 3-19 together with typical emission levels for different fuels and electricity generation technologies. The CO_2 emissions per GWh were calculated for 1998 using CO_2 emission and electricity generation data reported by the IEA (2000a, 2000b, 1999c) for public generation and autoproducer facilities. Carbon dioxide emission and electricity generation data are summarized for the APEC economies in Table B-5, Appendix B.

Malaysia and New Zealand reported the lowest two emission factors for the power sector in tonnes CO_2 per GWh of electricity produced, while Russia and PR China reported the two highest emission factors. The emission level for Viet Nam, which is near 3,500 tonnes CO_2 per GWh, has been excluded from the comparison of APEC economies because it is unreasonably high even for the least efficient power generation technologies and suspected to be unreliable. The CO_2 emission factors for the APEC economies reflect use of a mix of the available electricity generation technologies with a value between the ranges possible with in-use technologies. Room exists to lower the average emission factors with increased use of more efficient technologies.

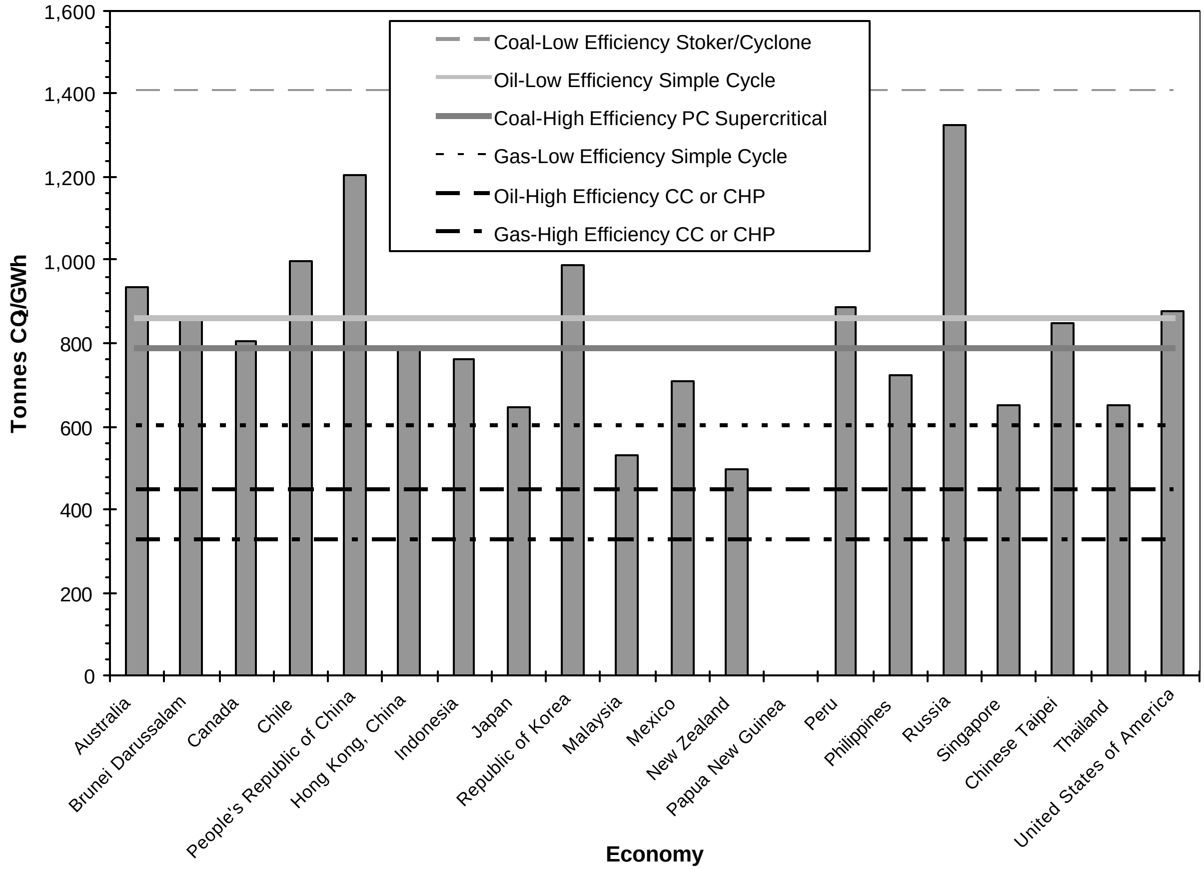


Figure 3-19 **CO_2 Emissions from Fossil Fuel Combustion for Electricity Generation - Public and Autoproducers**

4. Review of CO_2 Reduction Options for Fossil Fuel Electricity Generation

4.1 Importance of Energy Efficiency and Fuel Selection

Since greenhouse gas (GHG) emissions from electricity generation are, for all practical purposes, comprised of CO_2 emissions, improvements in efficiency are a direct means of reducing GHG emissions. To illustrate the benefits of improvements in plant efficiency, the following benefits are estimated for a 0.1% point increase in efficiency (e.g., 36.0% to 36.1%) for a 2000 MW coal-fired power station (Mandle, 1996).

- reduces fuel burned by 14,500 tonnes per year
- reduces SO_2 by 400 tonnes per year
- reduces NO_x by 100 tonnes per year
- reduces CO_2 by 31,000 tonnes per year

A 1.0% point increase in plant efficiency (e.g., from 36.0% to 37.0%) would provide ten times the reduction in fuel consumption and emissions indicated above for the case of a 0.1% point increase in efficiency.

When presenting efficiency data it is important to emphasize the difference between *percentage points* and *percentages*. For example, consider a conventional power plant operating at 36% efficiency which is upgraded to raise efficiency by 3 percentage points to 39%. This yields a reduction in CO_2 emissions for the same useable output according to the following formula:

Percent CO_2 reduction = $100\,(1 - (\eta_{before} / \eta_{after}))$

where,

η_{before} = net energy efficiency of plant before improvements

η_{after} = net energy efficiency of plant after improvements

Thus, the CO_2 reduction in this case is 100(1 - (36% / 39%)) = 7.7%

As another example, if a conventional gas-fired plant at 36% efficiency were repowered with a GTCC plant at 60% efficiency, then emissions for the same output would be reduced as follows:

CO_2 reduction = 1 - (0.36 / 0.60) = 40%

In addition to efficiency, the choice of fossil fuel is critical to CO_2 emissions in electricity generation. Figure 4-1 illustrates the importance of fuel and efficiency with tonnes of CO_2 per GWh electricity plotted against net plant efficiency for coal, oil, and natural gas fuels.

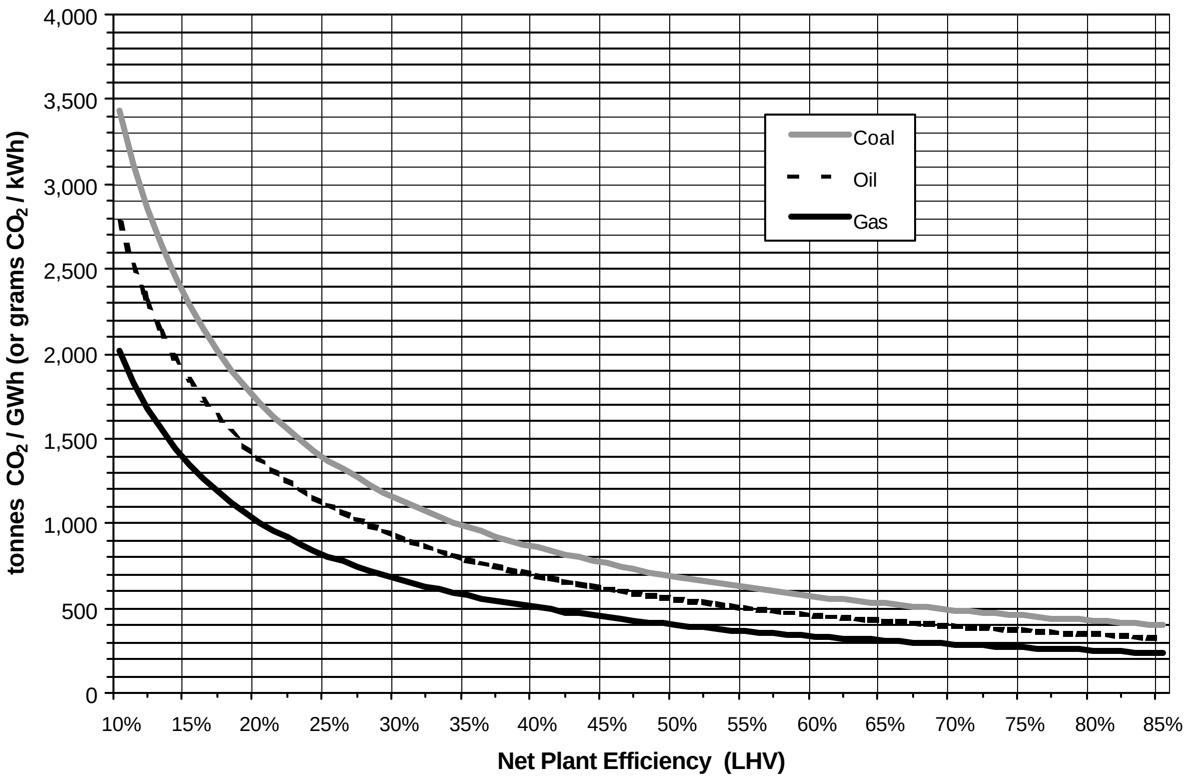


Figure 4-1 CO_2 Emissions as a Function of Net Plant Efficiency for Electricity Generated Using Fossil Fuels

For example, consider a new generation plant that has a net plant efficiency of 40%. If this plant were fuelled by natural gas, the CO_2 emissions would be 505 tonnes CO_2 per GWh. The same 40% efficiency plant firing oil would emit 693 tonnes CO_2 per GWh (37% higher), and 858 tonnes CO_2 per GWh (70% higher) if firing coal.

4.2 EMERGING FOSSIL-FUEL TECHNOLOGIES

4.2.1 Emerging Technologies for Coal

New technologies for coal-fired electricity generation are primarily focused on integrated gasification combined cycle (IGCC) and pressurized fluidized bed combustion (PFBC). These technologies have already been discussed in Chapter 3. The obvious benefit from these technologies relevant to CO_2 emissions is the improvement in net plant efficiency. Consider a new 1,000 MW (1 GW) coal-fired plant which operates 8,000 hours per year at full load (roughly 90% capacity factor), thus generating 8,000 GWh of electricity annually. The annual CO_2 emissions from such a plant would be as follows:

- PC subcritical (36% efficiency, 953 t CO_2/GWh): 7.6 Mt CO_2 annually

- PC supercritical (40% efficiency, 858 t CO_2/GWh): 6.9 Mt CO_2 annually (10% less than subcritical)
- IGCC (44% efficiency, 780 t CO_2/GWh): 6.2 Mt CO_2 annually (18% less than subcritical)

This example illustrates that the CO_2 reduction for an IGCC plant relative to a conventional, subcritical steam plant would be 1.4 Mt CO_2 annually, or 55 Mt over a typical plant life of 40 years.

Table 4-1 summarizes the key technical and economic characteristics and the development status of commercial and near-commercial clean coal technologies for new coal-fired power plants. For this range of technologies, IGCC achieves the highest efficiency and the lowest CO_2 emissions, but at the highest capital cost. A cost analysis was reported by Torrens (1996) from a study of a 600 MW PC-fired plant in Asia, which considered three design steam pressures: 16.5 MPa subcritical, 24.0 MPa supercritical and 31.0 MPa ultra supercritical. The plant was assumed to include an electrostatic precipitator for control of particulate matter emissions and low-NO_x burners for control of NO_x emissions, but no post-combustion SO_x or NO_x control. The subcritical plant had an efficiency of 38% LHV, compared to 41% for the supercritical and 45% for the ultra supercritical. The total plant capital cost was $800/kW for the subcritical plant, and increased by only 1.4% for the high pressure cases, which differs significantly from the cost increases for higher-pressure plants shown in Table 4-1.

Table 4-1 Nominal Technical and Economic Status of Coal Power Plant Technologies

Criteria	Sub Critical PF	Supercritical PF	AFBC	PFBC Combined cycle	IGCC
Status	proven	proven	proven at <300 MW	5 commercial units*	1 commercial unit*
Size range	wide range	wide range	small units	currently 2 sizes	large only
Fuel flexibility	range of coals	range of coals	very flexible	uncertain	uncertain
Net Efficiency %, LHV	36-38	40-46	34-40	42-45	43-48
Operational Flexibility	limited at low load	limited at low load	wide range	similar to AFBC, but uncertain	needs demonstration
Availability	excellent	good	limited experience	limited experience	uncertain
Cost US$/kW	900-1300	950-1600	1000-1600	1100-1500	1200-1600

* at time of IEA studies

Source: IEA (1996) and IEA (1997b) after Lefevre and Todoe (2000).

Extensive research and development of clean coal technology (CCT) is continuing by the U.S. Department of Energy and industry, including the CCT program and the Vision 21 Program (Smouse, et al., 2000, U.S. DOE, 2001a). Ando (2000) describes some of the research and development in Japan also aimed at developing advanced clean coal technology to support expanding global use of coal for energy in the 21st century.

The Vision 21 program in the United States is aimed at developing highly efficient and low-emitting technologies for coal fuels, with the ultimate goal of developing a virtually pollution-free energy plant that produces electricity together with other products. The program builds on technologies already being developed, including low-polluting combustion, gasification, high efficiency furnaces and heat exchangers, advanced gas turbines, fuel cells, and fuels synthesis, and supports research and development of other critical technologies and system integration efforts. The advanced coal technologies presently being designed, tested and evaluated under the CCT program include IGCC, circulating and bubbling bed PFBC, natural gas combined cycle and pulverized coal fired supercritical boiler technologies. Plant configurations, specifications and performance data for the technologies under development are summarized in Table 4-2. Net plant efficiencies for coal fired technologies range from a low of 40.5% for a 400 MW PC supercritical plant to 48% for an air-blown IGCC plant.

Table 4-2 Summary of Performance Results from the U.S. DOE/Industry CCT Program

System	IGCC Air-blown	IGCC Air-Blown	IGCC O2-Blown	CPFBC* High Power	CPFBC* High Effic.	PFBC Bubbling Bed	PC Plant Supercritical	Gas GTCC
Gasifier	KRW Fluid bed	KRW Fluid bed	Destec Entrained Bed					
Net Power (MW)	385	198	348	431	379	425	404	323
Gas Turbine	Westing-house	Westing-house	Westing-house	Westing-house	Westing-house	ASEA		Westing-house
Gas Cleanup	Ceramic candle	Ceramic candle	Ceramic candle	Ceramic candle	Ceramic candle	Two-stage cyclone	ESP	
FGD	Transport reactor with Zn sorbent	Transport reactor with Zn sorbent	Bed with Zn sorbent	Limestone	Limestone	Limestone	Wet Limestone	
Sulphate Recovery	Sulfator	Sulfator	Sulphuric acid	Landfill	Landfill	Landfill	Gypsum landfill	
NO_x Cleanup	Staged combustion	Staged Combustion	Staged combustion	Staged combustion	Staged combustion	Combustion temperature control.	Low NOx burner	Dry Low-NOx Burner
Heat Rate (Btu/kWh LHV)	7,175	8,006	7,451	7,389	7,200	8,268	8,435	6,148
Efficiency, (% LHV)	47.6**	42.7	45.8	46.2	47.4	41.3	40.5	55.6
CO_2 Emission (gCO_2/kWh)	681	760	684	698	679	782	785	364

* Circulating pressurized fluidized bed combustor.

** The plant efficiency reported in other publications suggests a value near 46% for this technology.

Source: U.S. DOE, 1999.

4.2.2 Emerging Technologies for Gas and Oil

Current gas turbine technology has such superior reliability, cost, and environmental benefits that it now dominates the market for new gas and oil power plants (IEA, 2000c). One strong indicator of this trend is that Alstom Power, a long-standing industry leader in boiler manufacturing, ceased producing conventional gas-fired utility boilers in the year 2000 (EIA, 2000).

The design efficiency for large gas turbine plants provided by major suppliers, as reported by Greth and Susta (2001), are summarized in Table 4-3. Ongoing technology developments are focused upon improving the design of new GTCC plants to reliably achieve 60% net plant efficiency and higher (IEA, 2000c). Key design variables in the advancement of gas turbine technology are (Ramanan, 2001; Greth and Susta, 2001):

- increased turbine temperatures, achieved via special cooling techniques and advanced materials and coatings
- optimised compressor and turbine aerodynamics
- advanced control systems
- optimised cycle design

Table 4-3 Efficiency and Output Specifications for Large GTCC Systems

Manufacturer	Thermal Efficiency (% LHV)	GT Output (MW)	ST Output (MW)	Total GTCC Output (MW)	Frequency (Hz)
Alstom Power (formerly ABB)	56.6	176	84	260	60
	57.0	258	120	378	50
GE Power Systems	57.3	181	99	280	60
	56.7	252	139	391	50
	60.0	Mono-Block		400	60
	60.0	Mono-Block		480	50
Siemens Westinghouse	55.8	2 x 182	197	561	60
	58.0	250	115	365	60
	57.3	2 x 256	282	705	50
Mitsubishi Heavy Industries	56.7	178	103	281	60
	58.0	247	124	371	60
	56.9	262	136	398	50
	58.2	324	160	484	50

Source: Greth and Susta, 2001

Another emerging technology for gas and oil fired plants is distributed generation. Distributed generation refers to small-scale technologies that generate electricity and heat at a site close to the source of energy demand. Its benefits include power quality, reduced need for long-distance, high-tension electricity transmission lines, and energy efficiency. Current efforts to further develop oil and gas fired systems are focusing on advanced gas turbines and fuel cells (Pierce, 2001; IPCC, 2001a). CHP for industrial applications is expected to be the largest potential market for distributed technologies in developed economies. In developing economies, rural areas that do not have electricity transmission infrastructure are a potential market for distributed generation, assuming oil or gas transmission infrastructure is adequate for such developments.

4.3 EXISTING PLANTS: COMBUSTION SYSTEM IMPROVEMENTS

4.3.1 Combustion Improvements for Fossil Fuel Boilers

A summary of typical combustion upgrades applicable to gas, oil, and coal boilers is shown in Table 4-4. Additional upgrades specific to coal-fired boilers are shown in the next section. Additional benefits of combustion improvements beyond efficiency improvement and reduction in CO_2 emissions include:

- Fuel cost savings
- Reduced NO_x
- Boiler life extension
- Plant reliability
- Improved ash quality (coal)

Reference is made throughout this Section to information available from the Australian Greenhouse Office in support of their program to implement efficiency standards for power generation (AGO, 2000a; 2000b). Means of increasing power plant efficiency presented in the most recent release of the Technical Guidelines for generator efficiency standards (AGO, 2001) are included in their entirety in Appendix D of this report for ease of reference.

Additional information on steps that can be taken to reduce carbon dioxide and pollutant emissions from conventional power generation systems is also available in a handbook available from the U.S. Energy Association (1999). In addition to options for power plants, this document reviews options for power transmission systems, demand-side management, emission off-sets and regulatory reform.

Table 4-4 Combustion Upgrades for Fossil Fuel Boilers (Gas, Oil, and Coal)

Upgrade	Description of Upgrade	Potential Efficiency or Other Benefits
Combustion Controls	• programmable logic controllers (PLC's). • field devices. • instrumentation.	• Reduce excess air (dry gas losses). Reduce unburned carbon. • Load ramping/cycling improvement.
Burner Retrofit	• burner (include scanners, ignitors). • air registers/dampers.	• Reduce excess air (dry gas losses). Typically driven by need to reduce NO_x emissions.
Air Distribution Improvements	• windbox compartments, perforated plate, baffles, dampering.	• Reduce excess air (dry gas losses).
Air Preheater Improvements	• new heat transfer elements (baskets). • mechanical upgrades (seals). • complete replacement (e.g., heat pipe air heaters, tubular to regenerative upgrade).	• Improved air preheater to recover heat into feedwater and reduce stack temperature. • Reduced air and gas leakage. • Increased efficiency.
Forced Draft and Induced Draft Fan Upgrades	• rotor/shaft replacement (e.g., higher efficiency blade design). • switch motor to high efficiency variable speed drive or steam turbine drive.	• Improved fan efficiency and increased fan capacity can both be achieved. • Reduced auxiliary power consumption.

References: (Mandle, 1996); (Nalbandian and Carpenter, 2000); (Stultz and Kitto, 1992); (Vernon, 1999); (Smith, 1999)

4.3.1.1 Combustion Instrumentation and Controls

Combustion control upgrades can provide substantial improvements in thermal efficiency. These upgrades typically include control hardware (e.g., replace old pneumatic controls with digital PLC's), instrumentation such as O_2 monitors or combustion air flow meters, as well as field devices such as dampers and valve actuators. A study for the Australian Greenhouse Office

(AGO) concluded that improved combustion controls can improve efficiency by up to 0.45% points[1].

Combustion controls may be incorporated into a more comprehensive digital/distributed control system (DCS) upgrade to significantly increase operating efficiency of cycling (non-base-loaded) plants which constantly ramp up or down in load (Binstock, 1995). See Sections 4.4.1.5 and 4.5.1.2 for further discussion of advanced control systems.

4.3.1.2 Burner Retrofit

Burner retrofit programs are usually driven by the need to reduce NO_x emissions, and there is a large volume of literature on low-NO_x burner (LNB) upgrades (Steitz and Cole, 1996; Garner, 1997). Since reducing NO_x typically involves reducing excess air, efficiency improvements are typically achieved simultaneously. A critical aspect of LNB retrofit programs is addressing the potential unfavourable side effects of off-stoichiometric firing and reduced excess air such as (Nalbandian and Carpenter, 2000):

- unburnt carbon in ash
- slagging, fouling, and corrosion
- CO emissions
- burner pressure drop

Seldom can retrofit of LNB alone suffice to increase efficiency and reduce CO_2 (and NO_x) emissions. There is typically an optimum package of upgrades needed to offset the potentially harmful side effects of LNB, which will vary for every plant depending on such key parameters as:

- ♦ baseline condition (e.g., a boiler with no existing slagging problems versus a boiler which already exhibits slagging problems; a boiler which is already limited by the forced draft (FD) fan capacity may need to include FD fan replacement).
- ♦ fuel type and fuel properties (e.g., slagging is not an issue with gas; low-volatile coals tend to exhibit higher unburnt carbon than high-volatile coals; heavy fuel oils versus distillate oils).
- ♦ project goals (e.g., if boiler capacity increase is a goal along with efficiency improvement and NO_x reduction, compared to a case where increased capacity is not a goal).

The AGO (2001) reports that low excess air operation, such as achieved via low-NO_x burners, can improve plant efficiency up to 1.1% points.

4.3.1.3 Air Distribution Improvements

Distribution of combustion air can be modified to increase boiler efficiency. While the air registers or burner dampers can be used to mitigate minor deficiencies in combustion air distribution, ideally a boiler will have equal distribution of combustion air throughout the windbox. Typical upgrades include use of baffles, perforated plate, or compartmentalization of the windbox. The type of modification would depend on the boiler type (e.g., wall-fired versus

[1] Efficiency improvements in the AGO Technical Guidelines are stated as percent higher heating value of the fuel, and have been converted for use throughout this report to percent lower heating value of the fuel, rounded to the nearest 0.05% point.

tangential), and the success of any such modifications could be improved by undertaking physical cold flow modelling or computer-assisted CFD analysis in the design phase.

Coal-fired stoker boilers, generally described in Chapter 3, have relatively unique air delivery systems which create opportunities for improvements. Modifications to control the distribution of under-grate and overfire air flows can reduce excess air requirements and unburnt carbon. Such modifications may include modification to the combustion air pathways (e.g., baffles) or redesigned damper arrangements, often combined with upgraded air metering and controls. The specific modifications would depend on stoker design (underfeed, overfeed, or spreader) and unit-specific baseline conditions.

4.3.1.4 Air Preheater Improvements

An air preheater (APH) is an important part of the combustion system as it recovers heat from exiting flue gas and transfers it into the incoming combustion air. Ideally a boiler will operate at a near the minimum stack temperature that avoids condensation of moisture or acid gases (e.g., SO_3 to form sulphuric acid). Many older boilers are equipped with a tubular APH, which can be less efficient than regenerative (e.g., Ljungström™) or heat pipe APH designs. Regenerative APH designs are employed in many large utility boilers and are amenable to low cost upgrades to replace heat transfer "baskets" with new designs, and new seals to minimize leakage of gas and air (Kitto, et al., 1996).

On line monitoring of APH performance can identify opportunities for minimising efficiency losses. Monitoring of air and gas O_2 and temperatures at the inlet and outlet is ideal.

One reported result, typical of air preheater improvements, is 0.15% points efficiency gain by "improvement in air heater surface areas" (Mandle, 1996). The AGO (2001) reports that up to a 0.25% point improvement in efficiency can potentially be achieved by restored, as well as well-maintained, APH components. Complete air preheater replacements, where warranted, could reasonably achieve in the order of a 2.0% point gain in efficiency.

4.3.1.5 Forced Draft and Induced Draft fan Upgrades

Forced draft (FD) and induced draft (ID) fans are significant consumers of auxiliary power for thermal power plants. These large utility boiler fans can be upgraded to improve efficiency in two general ways: improve fan performance, and improve motor performance.

Improved fan performance can be achieved by replacing the fan rotor and shaft assembly within the existing housing, or by replacing the entire fan. Older fans can achieve efficiency improvement by retrofitting with improved blade designs such as airfoil fan blades. Improvements can also be made in the fan control method, for example, by replacing inlet damper control with inlet guide vanes.

Fan motors can be replaced with new high efficiency designs, although the cost effectiveness of such upgrades is more attractive for base-loaded units where other benefits can be obtained such as fan capacity increase. For plants that operate in transient modes and at low loads, fan efficiency can be substantially lower than full-load, steady load operation. Such plants may find variable speed drive (VSD) upgrades to be economically attractive. VSD upgrades along with advanced couplings (e.g., fluid or magnetic) can decrease motor energy consumption by 20-30% (Guangyao, 1996). An improvement in efficiency of 0.35% points is achievable by use of VSD's on major plant equipment, according to information reported by the AGO (2001).

Conversion to steam turbine driven fans is another potential upgrade to increase efficiency. Such upgrades must take into consideration cold startup capability. If necessary for plant reliability, dual drives (electric and steam) can be installed on the same fan, or there may be another cold startup steam boiler in the same power station to provide reliable auxiliary steam supply.

4.3.2 Additional Combustion Improvements Unique to Pulverized Coal-Fired Boilers

The upgrades described in Section 4.3.1 are applicable to gas, oil, and coal boilers. However the fuel delivery and processing of PC-fired boilers create unique problems and thus present significant opportunities for efficiency improvements. Pulverized coal (PC) also represents the single largest technology employed for fossil fuel electricity generation in APEC. The data in Chapter 3 estimates there was over 630,000 MW (630 GW) of capacity, generating over 3,600 billion kWh of electricity, and emitting nearly 3,400 million tonnes of CO_2 in the year 1998. Therefore, upgrades to PC plants represent a large potential reduction in CO_2 emissions in the APEC power sector.

A summary of combustion system upgrades applicable to PC boilers is listed in Table 4-5.

Table 4-5 Summary of Combustion Upgrades Applicable to PC-Fired Boilers

Upgrade	Description of Upgrade	Potential Efficiency or Other Benefit
Sootblowers	• New sootblower designs • New sootblower controls and/or procedures	• Improve furnace heat absorption. • Reduce slagging • Enable reduced excess air
Coal Feeders	• Replace volumetric feeders with gravimetric. • Refurbish/upgrade older gravimetric feeders.	• Balance coal to burner elevations. • Reduce slagging, fouling, unburnt carbon. • Improve ash quality • Enable reduced excess air.
Pulverizer	• Grinding: new rings, rollers, etc. depending on design. • Drying: high efficiency exhauster wheels (suction-type) or PA fans (forced air-type) to increase PA flow. • Drying: APH modifications or installation of duct burners to increase PA temperature. • Classify: improved static classifiers. • Classify: retrofit with dynamic (rotating) classifiers.	• Reduce auxiliary power consumption • Improve fineness (reduce unburnt carbon and/or reduce excess air) • Improve ash quality • Increase pulverizer capacity • Maintain design fuel temperatures. • Enable flexibility to purchase wider range of coals.
Coal Piping	• Riffles/distributors, • coal flow balancing devices (pipe-to-pipe and/or coal roping. • On-line coal flow monitoring*.	• Balance coal to individual burners • Reduce slagging, improve ash, reduce excess air

* See Nalbandian and Carpenter (2000) for a discussion of on-line coal flow monitoring.

4.3.2.1 Sootblowers

Sootblowers are important in controlling combustion and heat transfer in coal-fired boiler furnaces. Sootblowers can be replaced or reconfigured to control slagging in the furnace, optimise heat transfer, enable reduced excess air (reduce dry gas losses), and reduce attemperator flows. A common method to mitigate furnace slagging problems is to operate with increased excess air. The need to increase excess air can often be partly offset with improved sootblowing. Improved sootblowing can involve:

- New or upgraded sootblower hardware.
- Upgrade sootblower controls (e.g., frequency, duration, and location), or automate manual sootblowing practices.
- Modify sootblowing procedures (operator activity) where sootblowing is partly or completely a manual operation.
- Add instrumentation or monitors to enable more effective sootblowing such as tube temperature monitoring or use of furnace cameras.

One plant attributed a 0.2% points increase in net efficiency by using a sootblowing optimization computer-controlled system (Simander, 1997). The AGO (2001) indicates a potential increase in efficiency of 0.9% points from improved boiler cleaning through off-load cleaning or use of better sootblowers, water blowers and water cannons. Installing additional sootblowers to keep boiler surfaces cleaner was estimated to offer an efficiency gain of 0.35% points.

4.3.2.2 Feeders

Coal feeders control the flow rate of crushed coal to the pulverizers. Typically, but not always, one feeder supplies coal to one burner elevation (or perhaps groups of two feeders, each two supplying one elevation). Many older boilers are equipped with volumetric feeders, which do not account for variations in density due to moisture and size. Unequal coal flow through the feeders carries through the system of pulverisation and combustion in the furnace, with the effect of uneven wear on pulverizers and imbalanced combustion.

Ideally, each feeder supplies an equal mass flow rate to the pulverizers to provide the primary level of control over balanced fuel and air for optimum combustion. This is accomplished with gravimetric feeders. These are equipped with load cells and, in recent years, microprocessor controls to meter and control the feed rate of coal to the desired set point. Any fuel system upgrade for purposes of efficiency should include an assessment of coal feeders, with consideration of upgrading to gravimetric feeders. Plants with gravimetric feeders should be assessed for controls or load cell replacements to ensure accurate metering and flow control.

4.3.2.3 Pulverizers

Coal pulverizers perform three basic functions: grind, dry, and classify the coal. These three functions also represent a logical grouping of pulverizer upgrades. The primary air (PA) must be supplied at adequate temperature and flow rate to dry and transport the PC particles.

Coal grinding is accomplished in a variety of designs incorporating rollers or balls to grind the coal in an air-swept pulverizer. Depending on the manufacturer, there is a range of OEM and non-OEM suppliers of performance enhancing modifications to pulverizers. For example, ringroll pulverizers such as manufactured by ABB have available upgrades to the components such as rings, rollers, and vane wheels (Storm, 2001).

For PC plants that experience low coal pipe temperatures or where it is desirable to purchase higher moisture coals, improvements in drying capability should be evaluated. Increasing the PA flow or temperature are the two basic parameters to improve coal drying. If the pulverizer (or hot PA fan) can allow increased PA temperature, then air preheater modifications can provide smaller increases in temperature. Where a larger temperature increase or direct control over PA temperature is needed, then gas or oil duct burners can be employed. Recirculating flue gas to the primary air is another viable technique. The properties of the coal and design temperature limits of the pulverizer must be carefully evaluated to ensure component temperature limits are not exceeded, or perhaps more critically, that an increased potential for pulverizer fires is not created, such as can occur with high-volatile coals. Increasing the operating temperature may create the need for pulverizer inerting systems.

Classification of coal particles is a basic function of pulverizers. As air-entrained coal particles leave the grinding zone, classifiers control the particle size that exits to the coal pipes and boiler using particle centrifugal forces whereby the larger particles fall back into the grinding zone. Typical static classifiers recycled particles in the range 60-80% that are of acceptable cut off size. Retrofit of dynamic classifiers (Slezak, et al., 1999) results in large improvements in classification whereby recycled particles may be reduced to roughly 30-40%.

The benefits of upgrading coal pulverizers include:

- Reduce auxiliary power consumption.
- Improve fineness (reduce unburnt carbon and/or reduce excess air).
- Improve ash quality.
- Increase pulverizer capacity.
- Maintain design fuel temperatures.
- Enable flexibility to purchase wider range of coals.

4.3.3 Gas Turbine Combustion Improvements

Generally the focus of combustion improvements is on conventional steam boilers, and this is clearly where the most benefits could be derived in terms of CO_2 reduction. Nonetheless, there are opportunities to improve efficiency through combustion improvements of gas turbine plants.

The open Brayton cycle is employed for conventional fossil fuel power generation using gas turbines. In the simplest arrangement, air is compressed, fed to a gas- or oil-fired combustion, then expanded through a gas turbine and exhausted to atmosphere. The gas turbine shaft powers the compressor and an electrical generator. Typically a simple cycle gas turbine can convert 25-32% of the fuel input into shaft output (Stultz and Kitto, 1992), with the balance of energy leaving with the exhaust gas. There are four basic upgrades to a standard Brayton cycle gas turbine:

Regeneration (Recuperator)

A counterflow heat exchanger is added to the cycle to recover heat from the turbine exhaust to heat the compressed air. This is the single most beneficial combustion system improvement to gas turbine plants (for those not already so equipped). Fuel consumption can be reduced by 20-30% (e.g., a cycle efficiency of 25% could increase by 5% points or more) by use of a recuperator (El-Walkil, 1984; Stultz and Kitto, 1992) offset by some reduction in peak capacity. Recuperators can potentially be retrofit to existing gas turbines as part of a repowering or major upgrade of a plant.

Compressor Intercooling

Heat exchangers are employed to cool the air between stages of the compressor, thus reducing compressor work and improving efficiency. This would not typically be suitable for retrofit, but is a feature integrated in all advanced GTCC designs.

Turbine Reheat

Increasing the gas temperature through the turbine can increase cycle efficiency and turbine output. While the peak temperature is limited by material limits, inserting staged reheat of gas (by sending to the combustion) part way through the turbine accomplishes this. This would not typically be suitable for retrofit, but is integrated in all GTCC advanced designs.

Water injection

By injecting water into the compressor, evaporation cools the air thereby reducing compressor work and marginally increasing cycle efficiency. The larger benefit is the increased mass flow increases cycle output. Water injection has the potential to be retrofit to existing gas turbines.

Efficiency gains potentially achievable by operational changes and upgrades to gas turbines are summarized by the AGO (2001) as follows:

- up to 0.35% point increase by replacing or cleaning dirty inlet air filters to reduce pressure drop;
- up to 0.9% point increase by retrofit of inlet air cooling systems (chiller, evaporative cooler or mist/fog system);
- up to 0.45% point increase by improved compressor cleaning and maintenance;
- up to 0.45% point increase by control system improvements, such as checking inlet guide vanes, instrument calibration and ensuring equipment is operating correctly;
- up to 0.25% point increase with improved inlet air and exhaust duct design to reduce pressure losses.

Critical factors in evaluating gas turbine efficiency improvements are capital cost, peak load, startup time (e.g., peaking units), operating cost, and intended capacity factor.

4.4 EXISTING PLANTS: STEAM CYCLE IMPROVEMENTS

Steam cycle improvements have been grouped into five categories:

- Boiler
- Steam Turbine
- Condensing System
- Cycle Isolation
- Steam Cycle Upgrades Applied to GTCC Plants

4.4.1 Boilers

All major steam cycle components of fossil fuel boilers are potential opportunities for efficiency improvement and CO_2 reduction. A discussion of steam cycle efficiency improvement is provided below under the following headings:

- Heat Transfer Sections and Boiler Circulation
- Feedwater heaters
- Pumps
- Valves, Traps and Attemperators
- Instrumentation and Controls

4.4.1.1 Heat Transfer Sections and Boiler Circulation

Both OEM and, at least in some cases in North America, non-OEM equipment suppliers can design and supply improved efficiency components. Improvements include (Kitto, 1996):

- The convection and radiation heat transfer sections include the furnace, superheat, reheat, and economiser tube sections. Typical upgrades may include modified economiser tube spacing or tube geometry, new high temperature reheat and superheat headers utilising advanced materials, and heat transfer surface coatings.
- Circulation improvements to minimize efficiency losses from cycling and low load operation.
- Circulation improvements to increase peak boiler capacity and efficiency.

As an example (Mandle, 1996) reported efficiency gains for a 500 MW coal-fired plant in the UK were 0.20% points by "optimisation" of superheater and reheater panels, and an additional 0.20% points by increasing the size of the economiser. Addition of extra heat transfer surface can potentially increase efficiency by up to 0.7% points (AGO, 2001).

4.4.1.2 Feedwater Heaters

Improvements to design or heat transfer surfaces for existing feedwater heaters may result in improved efficiency and load improvement. Even low cost repairs to deteriorated equipment can provide immediate and substantial benefits. For example, feedwater repairs for a 404 MW coal-fired plant resulted in a 420 kW (0.1%) increase in plant output and 0.07% points plant efficiency increase (Coons and Dimmick, 1994). In some cases, defective feedwater heaters are removed from service for prolonged periods, adversely affecting plant efficiency. The AGO (2001) reports up to a 1.8% point efficiency gain and an increase in power output are possible by reinstating this equipment.

At higher costs and where existing plants predict substantial improvement potential, new feedwater heater designs and/or configurations could be installed.

4.4.1.3 Pumps

Boiler feed pumps as well as other smaller pumps such as make up water or drains in the steam cycle can be converted to higher efficiency motors to reduce auxiliary power. Variable speed drive (VSD) motors may be particularly beneficial for units with load cycling operation. The pump efficiency may also be improved by lower cost upgrades such as impeller replacements to move the operating point near the maximum efficiency point (Matusheski, 2000). Conversion of boiler feed pumps from electric to steam turbine driven reportedly increased plant efficiency by 0.4% points in one plant (Mandle, 1996). Conversion to steam turbine driven pumps must take into consideration cold startup capability. If necessary for plant reliability, dual drives (electric and steam) can be installed on the same pump.

4.4.1.4 Valves, Traps, and Attemperators

Repair or replacement of valves (control valves, isolation valves, check valves, relief valves), steam traps, and attemperators are good targets for low cost efficiency improvements. Generally, performance of these components is assessed as part of cycle isolation programs described in Section 4.4.3.1. Replacement of deteriorated components with newer designs that are more maintainable and/or more robust should be considered. Larger, higher cost components (e.g., main steam control valve) are potential candidates for refurbishment at a lower cost than replacement.

Superheat and reheat steam attemperators are used to maintain steam temperatures within design limits, and represent one of the more significant areas of controllable losses in fossil fuel boilers (Caudill, et al., 1998).

4.4.1.5 Steam Cycle Instrumentation and Controls

Consideration of instrumentation and control (I&C) upgrades to the boiler steam cycle is an essential element to any efficiency improvement program. These upgrades could be pursued as a stand-alone effort, or in conjunction with broader efforts to upgrade combustion system I&C or complete DCS programs for an entire plant, as described in Sections 4.3.1.1 and 4.5.1.2.

The focus of boiler steam cycle I&C improvements should be in the areas of controllable losses. Typically this includes main steam temperature control. One plant (Mandle, 1996) reported 0.15% points by reduction in attemperator spray flows and 0.10% points by improved controls to maintain design steam temperatures through control improvements. It is important to note that controlling main steam temperatures for maximum efficiency is generally a function of many factors, including operational aspects such as controlling excess air and sootblowing procedures, or maintenance practices (e.g., losses from a leaking reheat attemperator is beyond the control of the boiler operator).

Conventional base-loaded fossil boilers provide constant pressure steam from the boiler, which is throttled at the turbine inlet to vary pressure and load. This creates plant inefficiencies and higher thermal stresses in turbines when operated cyclically as steam temperatures into the turbine vary on the order of 100 Celsius. Sliding pressure operation is where steam cycle controls, feed pumps, and other modifications enable variable discharge steam pressure from the boiler, eliminating the need for throttling and providing constant temperature steam to the turbine. Sliding pressure can improve plant heat rate in the range of 0.5-3.5% points across the load range (Singer, 1991) through turbine efficiency and other improvements.

4.4.2 Steam Turbines

Steam turbine upgrades are available ranging from minor improvements, to major upgrades, to complete replacement. Steam turbines losses occur in six areas as shown in Table 4-6.

As an example of what can be achieved, a 404 MW coal-fired plant (Coons and Dimmick, 1994) reported 4,523 kW plant capacity increase (1.1%) and 0.7% point improvement in plant efficiency from the following low-cost steam turbine upgrades:

- Replaced radial spiral strips on high-pressure (HP) and intermediate pressure (IP) sections.
- Installed retractable interstage packing.
- Repaired solid particle erosion (SPE) damage to stationary diaphragms.
- Repaired station diaphragm flow path SPE in IP section.

Plant efficiency was improved for a number of plants, ranging from 0.5-1.6% points, by installing new, high-efficiency LP turbine blades and new packing (Mandle, 1996). An increase in plant efficiency of up to 0.15% points is potentially possible by reducing steam turbine leaks, while up to a 0.9% point increase is possible by installing new high-efficiency blades, according to the AGO (2001).

4.4.3 Condensing System

Steam exiting the last turbine stage is typically 88% quality (12% moisture) and must be condensed for pumping to boiler pressures. Condensers are typically very large shell and tube heat exchangers. For optimum performance, condensers must provide low back-pressure to the turbine, preserve water quality for reuse in the boiler, deaerate the condensate to minimize corrosion, and serve as the collection point for all plant water drains into the hot well.

Condenser performance, specifically back-pressure imposed on the steam turbine, is frequently cited as a source of lost efficiency (Matusheski, 2000; Stultz and Kitto, 1992; Caudill, 1998; Simander, 1997; AGO, 2001) and, hence, is an opportunity for efficiency gains. Estimates in the range of 0.5-1.0% points efficiency gain are common, with additional plant capacity often achieved as well. These gains can be achieved by sound maintenance practices to minimize water and air in-leakage, operator attention and awareness of increased backpressure and installing on-line condenser cleaning systems.

For fossil fuel plants that do not have a body of water for heat rejection, cooling towers are employed. Improvements in cooling tower performance can be achieved with upgrades such as one plant which replaced timber splash packs with plastic film-forming packs with a net 0.4% points increase in plant efficiency (Mandle, 1996). An AGO (2001) report estimates up to a 0.9% point efficiency increase can be achieved by installing new cooling tower film-type packs.

Table 4-6 Summary of Steam Turbine Losses

Type of Loss	Loss Description	Areas of improvement
Supersaturation	As superheated steam rapidly expands in the turbine it does not immediately condense, becomes *supersaturated*, and then condenses suddenly once a lower pressure is reached. This process results in loss in available energy.	Blade and nozzle design
Friction	Friction produces the largest losses in turbine in nozzles, blades, and rotors.	Blade, nozzle, rotor design
Leakage	Leakage within (e.g., between blade and housing) and to outside the turbine across packing.	Packing, blade-housing design
Moisture, chemical, solid particles.	Moisture losses result from liquid droplets impinging on blades, reducing mechanical work (output) of the rotor. Solid particles can erode blades. Chemical impurities can corrode components.	Turbine and steam flow controls, blade design, boiler water chemistry and treatment.
Leaving Loss	High exit velocities from last turbine stage	Blade design (height, speed); area of exhaust duct to condenser (e.g., exhaust hoods)
Heat Transfer	Conduction, convection, and radiation (typically negligible for large utility turbines)	Insulation
Mechanical	Losses between turbine and electrical generator, which are generally minimal	Mechanical design

(El-Wakil, 1984)

4.4.4 Cycle Isolation

Cycle isolation is a common term in the electric power industry, at least in North America, and refers to performance improvement programs focused on minimizing a large number of minor losses in the plant steam cycle. Cycle isolation programs integrate a number of basic elements to improve and retain efficiency gains over the long term. Sources of leaks must be evaluated for repair versus replacement decisions by plant staff, including assessment of upgrades as described in Sections 4.4.1 through 4.4.3. O&M improvements such as those described in Section 4.5 are important to achieving ongoing minimisation of leakage losses.

Sources of leaks may be ascertained by plant instrumentation such as increased boiler make-up water (Matusheski, 2000), or by planned leak detection programs utilising acoustical measurements (Stultz and Kitto, 1992). Cycle isolation can be planned as a comprehensive program including all steam and water equipment such as boiler tube sections, feedwater, steam turbine, and condenser subsystems. Some programs may focus on areas known to hold the most potential improvement based on plant-specific history (e.g., just the turbine, or just the feedwater and drains, etc.). Examples of leak minimisation programs include:

- A 404 MW plant achieved a total of 13.1 MW (8.0%) increase in output and approximately a 2.7% point increase in net plant efficiency through cycle isolation of valves, steam traps, and IP/HP steam turbines (Coons and Dimmick, 1994). For this plant 75% of the gain in both plant output and efficiency was attributed to leak minimisation of traps and valves, and 25% was attributed to steam turbine improvements.

- A plant achieved a 1.5% point increase in net plant efficiency through cycle isolation of only valves (Branco and Stuckmeyer, 1991).
- A plant achieved approximately a 2.0% point increase in net plant efficiency through cycle isolation (Hopson, 1985).

4.4.5 Steam Cycle Improvements Applied to GTCC Plants

The steam cycle portion of GTCC plants are generally subject to the same upgrades as for conventional boiler steam turbine plant. However, since only a portion of the cycle is steam, then overall plant efficiency improvement is less. For example, a typical GTCC plant may generate 60% of net electricity generation from the gas turbine and 40% from the steam turbine, so steam cycle efficiency gains in net plant output would be less than half of that for a conventional thermal plant.

4.5 EXISTING PLANTS: OPERATION AND MAINTENANCE IMPROVEMENTS

One of the key principles involved in power plant efficiency improvement is the difference between a performance-tested, short-term achievement versus ongoing, long-term efficiency improvement. For example, a one time low-cost refurbishment of a plant may increase efficiency by 1.5% as proven by pre- and post-retrofit performance tests. However these efficiency gains will deteriorate over time unless sustained by focused O&M programs. The key to turning short-term efforts into annual savings is sound O&M staffing, procedures, systems, and tools.

4.5.1 Operation

Operation improvements in support of plant efficiency and CO_2 reduction includes the following areas:

- Training
- Tools
- Staffing and Organization

4.5.1.1 Training

Training of O&M staff on the fundamentals of plant efficiency, supported by procedures and other parallel measures, is reported to achieve substantial improvements (Matusheski, 2000). Such programs include:

- training staff on heat rate fundamentals,
- interviewing experienced staff for feedback,
- establish procedures for minimising controllable losses,
- increase overall awareness of impacts on plant efficiency
- integrate training as an ongoing part of performance and efficiency improvement.

Training programs are reported to improve efficiency by 0.25-0.50% points in a typical fossil fuel plant (Caudill, 1998).

The U.S. Energy Association has organized over 75 cooperative partnerships between U.S. organizations and counter-parts in developing economies (USEA, 2001). These partnerships promote efficient and environmentally sustainable production and use of energy and include measures to mitigate climate impacts in the energy sector. These activities include projects to improve the training of management and operating personnel. A partial list of partnership program activities in the APEC region includes projects with: Shandong Electric Power Group in PR China to improve the environmental performance and efficiency of coal-fired power plants; PT PLN Java-Bali Power Company in Indonesia to increase generation efficiency through optimized operation and maintenance procedures; and the Energy Regulatory Board in the Philippines for regulatory initiatives and demand side management. More information on USEA partnerships can be found on the Internet at www.usea.org.

4.5.1.2 Tools

Providing operators with effective tools for monitoring and controlling plant efficiency is essential to sustain optimum efficiency over the long-term. Online performance monitoring (OPM) systems include software and hardware that can be applied to existing plants to provide real time calculations of plant heat rate. Also, advanced artificial intelligence-based control systems are reported to achieve efficiency improvements on the order of 3-5% points (Nalbandian and Carpenter, 2000). Examples of these systems are products such as Ultramax™ and GNOCIS™.

OPM and artificial intelligence-based systems must be supported by accurate instrumentation to monitor critical parameters (Caudill, 1998), should be validated with performance test data (Hamzah, 2001), and include capabilities to produce meaningful trends and reports. Such systems can be installed as separate information systems, or included in DCS upgrades (Matusheski, 2000). OPM systems alone reportedly achieved net efficiency gains ranging from 0.3% points (Mandle, 1996) to 1.0% points (Caudill, 1998).

4.5.1.3 Staffing and Organization

Staffing and organisation is shown to have a measurable effect on plant efficiency (Caudill, 1998; Mandle, 1996; Matusheski, 2000). Integration of operating, maintenance, engineering, and management staff into groups and teams can be optimised to create energy efficient, cost-effective operation, and environmentally optimum results. There is no universal solution and the best organisation ultimately depends on corporate culture, economic considerations, plant-specific features, etc.

One option is to organise station staff into teams dedicated to specific subsystems such as fuel delivery or boilers or turbines for all units at large power stations, which are often referred to as "process or task area teams" (Mandle, 1996). Another option is to create multidisciplinary teams responsible for all processes and equipment for a specific unit or group of units (Scharnott, 2001). Performance improvement teams responsible for optimising energy efficiency such as a "Heat Rate Improvement Task Force" (Caudill, 1998) can be created. These teams can be assigned to oversee and/or support efficiency issues for process or unit teams.

4.5.2 Maintenance

In concert with operations, sound maintenance practices will lead to improved efficiency. Maintenance is an integral function associated with sustaining efficiency upgrades. Some efficiency improvement programs such as cycle isolation are more heavily a function of maintenance.

Computerized Maintenance Management Systems (CMMS) for preventive and corrective maintenance involve creating databases linked or integrated with software to maintain inventory, condition assessment, preventive maintenance schedule, and preventive/corrective maintenance history. Ideally the CMMS would be integrated with operations, such as linked to an OPM system. Sound maintenance of equipment such as boiler cleanliness, mechanical tolerances in pulverizers, etc. (Stultz and Kitto, 1992) are essential to operating boilers up to the design efficiency. Statistical process control (SPC) is another tool available to integrate in maintenance programs in order to maintain for efficiency (Matusheski, 2000).

As with operations, maintenance staff training to continuously improve knowledge and create awareness of controllable losses will produce efficiency benefits (Mandle, 1996).

Reliability Centered Maintenance (RCM) is a general approach to plant maintenance that primarily focuses on improving plant availability as applied to the power industry (Burchardt, 2001). However, RCM also contributes to plant efficiency improvements (Matusheski, 2000) when integrated with CMMS and OPM systems. RCM programs involve analyzing the function and failure modes of equipment in order to optimise plant reliability by tracking variables such as mean time between failure (MTBF) for critical equipment. Ideally, maintenance resources are focused upon these critical components, and timing is such that equipment is maintained only when it is needed. Often predictive maintenance techniques are used whereby real-time condition monitoring (e.g., vibration, temperatures, lubricating fluid quality) are employed to trigger maintenance activities.

On a regional level, reduction in planned and forced maintenance outages reduces greenhouse gas emissions. This is due to the fact that, when efficient base-load power plants are off-line, the demand tends to be met by less efficient power plants, with an associated higher greenhouse gas emission intensity (USEA, 1999).

4.6 REPOWERING

Repowering is an alternative to constructing a new greenfield power plant, and involves substantially upgrading of an existing plant in varying degrees. Five repowering categories are commonly used, and are referred to below using common terminologies:

- Full, or Station, Repowering
- Topping, or Hot Windbox, Repowering
- Parallel, or Compound, or Supplemental Repowering
- Feedwater, or Process, or Boosting Steam Turbines, Repowering
- Boiler, or Solid Fuel, Repowering

Plants with low capacity factors, which are scheduled for retirement, or which have been deactivated are potential candidate sites for repowering.

4.6.1 Full or Station or Site Repowering

Stenzel, et al. (1997), Stulz and Kitto (1993), Termuehlen (1998) and Nalbandian and Carpenter (2000) provide a current discussion of repowering options. Existing plant equipment is demolished, reusing only basic facilities as applicable such as transmission lines, fuel supply systems (e.g., gas pipelines or coal handling), and water systems (e.g., cooling towers, makeup or cooling water pipelines). *Full* repowering can involve new gas- or oil-fired GTCC plants, or new coal-fired plants constructed on the existing site.

Efficiency improvement and CO_2 reduction is a function of the fuel and technology employed in the new plant. For example, a 31% efficiency, coal-fired power station with two units and a total output of 675 MW was repowered with a 56% efficiency gas-fired GTCC plant (Stenzel, et al., 1997). As a result, CO_2 emissions were reduced by 70% from 7.65 Mt to 2.32 Mt per year, while simultaneously increasing electric generation by 10%.

4.6.2 Topping or Hot Windbox Repowering

In this approach, a new gas turbine is installed, which has been sized to supply combustion air to a pre-existing fossil fuel boiler that requires the windbox to be modified. The FD fan is partly or fully replaced by the GT exhaust. (Nalbandian and Carpenter, 2000; Stenzel et al., 1997)

4.6.3 Parallel or Compound or Supplemental Repowering

A new gas turbine with a heat recovery steam generator (HRSG) can be installed to provide superheated steam to an existing superheater outlet, or directly to existing steam turbines. The existing fossil fuel boiler remains in operation, except at a reduced output to offset steam from the HRSG. This creates a combined cycle plant with two steam generation systems linked at a common steam turbine.

4.6.4 Feedwater or Process or Boosting Steam Turbines Repowering

This is similar to parallel repowering, except steam from the new gas turbine and heat recovery steam generator is used to heat feedwater in the existing plant.

4.6.5 Boiler or Solid Fuel Repowering

With this approach, a new solid fuel (coal, biomass, and/or other solid wastes) combustion system is installed, such as an AFBC, PFBC (with or without a gas turbine) or an integrated gasification combined cycle configuration. Typically, the existing steam turbines would be reused (if steam turbines are also replaced, then this repowering option would more appropriately be classified as full repowering). One of the major benefits of repowering with fluidized bed technology is that SO_2 removal can be achieved when there is no space for installing FGD.

4.7 SWITCH TO LOWER CARBON FUELS

4.7.1 Lower Carbon Containing Fossil Fuels

In some cases, existing or new power plants can reduce CO_2 emissions by partially or completely switching to fuels having a lower carbon content per unit of heating value. The CO_2 emission reductions resulting from fuel switching are as summarised as follows:

a) Coal switch to gas: 43 tonnes CO_2 reduction per TJ of fuel fired (99 to 56 t CO_2/TJ).

b) Coal switch to oil: 25 tonnes CO_2 reduction per TJ of fuel fired (99 to 74 t CO_2/TJ).

c) Oil switch to gas: 18 tonnes CO_2 reduction per TJ of fuel fired (74 to 56 t CO_2/TJ).

Firing gas or oil as an alternative fuel can include adverse impacts such as unit derating or unfavourable heat release patterns in the furnace or convective passes of boilers. As an alternative to 100% fuel switching, co-firing can be employed as a means to reduce CO_2 emissions without the full impacts on fuel cost and operations. Emissions of SO_2, NO_x, particulates, and air toxics would be reduced by firing gas, and possibly by oil as well. Scenarios are presented in Chapter 5 for two basic strategies:

- 25% co-firing of gas or oil for plants reported to have existing capability for these as alternative fuels.
- 100% fuel switch to gas or oil.

4.7.2 Alternative Fuels

Biomass combustion for power generation can produce significant CO_2 reductions if the biomass is from renewable sources, and is foreseen as a cost-effective strategy for CO_2 emission reductions (IPCC, 2001a). CO_2 emissions from biomass are quantified for reporting, and then deducted in the net CO_2 emission figures. Two basic strategies are targeted: co-firing biomass with PC, and 100% biomass power generation. Both strategies rely upon fluidized bed combustion technologies. Biomass fuels are often cost competitive only when used close to the source of production as biomass can be costly to load, transport and unload for large transport distances by truck, rail or barge. Biomass energy systems tend to have a higher capital cost than fossil-fuelled systems and special attention is needed to biomass storage, handling and feeding operations. Biomass is an attractive alternative in small to medium capacities for distributed electricity generation or cogeneration of heat and power at industrial operations that generate biomass wastes, especially in rural agricultural areas and where there is limited power transmission infrastructure (PTM, 2000).

4.8 CO_2 CAPTURE AND SEQUESTRATION

Carbon dioxide sequestration is a process by which carbon dioxide is captured, either directly from the exhaust streams of industrial or utility plants, or indirectly from the atmosphere, then placed in long-term storage so as to avoid or minimize its effects on climate (Kane, 2001). Current technologies for CO_2 sequestration still require extensive development and refinement , and have known limitations including high energy penalties and cost associated with CO_2 capture technologies and potential impacts of exploratory CO_2 storage options.

This section provides an overview of CO_2 capture and sequestration options and their effects on plant performance. An increasing body of work exists on this technology that the reader should consult for additional information. Good summaries of the technology options and results of technical and economic feasibility studies can be found in the following information sources:

Meisen, 1997, "Research and Development issues in CO_2 Capture", Energy Conversion. Management, Vol 38;

Smith,1999, "CO_2 Reduction-Prospects for Coal", IEA Coal Research;

IEA Greenhouse Gas R&D Programme, http://www.ieagreen.org.uk/.

4.8.1 CO_2 Separation and Capture Technologies

Current technology choices for capturing CO_2 are expensive and limited. Many other technologies have been identified but further work is required for development. Some technologies for separating CO_2 from power facilities involve treating flue gases to remove carbon dioxide, while others involve pre-combustion feed gas modifications.

4.8.1.1 Absorption

During an absorption process, combustion flue gases are treated in a countercurrent flow of an aqueous absorbent solution such as mono-, di-, or tri-ethanol amines to chemically capture CO_2. With low concentrations of CO_2 in the flue gases, chemical solvents are preferred, while at high CO_2 concentrations, a physical solvent is preferred (IEA online). Physical absorption is achieved by the use of solvents such as polyethylene glycol di-methylether (Selexol) and propylene. Although the reversible characteristics of the absorption processes create an advantageous continuous process, the energy penalty and additional equipment requirements for circulating large volumes of liquid absorbents are significant cost and performance disadvantages and limit applications of the process (Meisen, et al., 1997).

4.8.1.2 Adsorption

The adsorption of CO_2 gas by use of molecular sieves (zeolites) is based on significant intermolecular forces between gases and surfaces of certain solid materials (Smith, 1999). There are two basic types: pressure swing adsorption, and temperature swing adsorption, which are being developed for use in combination. In Pressure Swing Adsorption (PSA) the gas flows through the reaction beds at elevated pressure and low temperature such that the adsorption reaches equilibrium at the bed exit. The feed is then stopped and the bed is regenerated by elutriation (Smith, 1999). Temperature Swing Adsorption (TSA) works on a similar principle with variation in temperature instead of pressure. The main advantage is the relatively simple, yet unsteady state operation. However, the removal of CO_2 by an adsorbent is most effective when the concentration in the flue gases lies between 400 ppm and 15,000 ppm, which is substantially lower than is normally the case with power stations. Coupled with limited capacity and poor selectivity, adsorption is unattractive for CO_2 capture from power generation (IEA online).

4.8.1.3 O_2/CO_2 Combustion

The use of pure oxygen or oxygen enriched air for combustion can improve the rate of combustion and increase the combustion temperature, thus leading to higher thermal efficiencies for the combustion of fossil fuels, especially in the case of coal. Product gases with high concentrations of CO_2 can be recycled and added to this feed stream to moderate the combustion temperatures (Meisen, et al., 1997). Theoretically, the concentration of CO_2 in the flue gas of a coal combustion process can reach 95% on a dry basis when firing with pure O_2 (Smith, 1999), greatly concentrating CO_2 for easier separation in the flue gas. The main disadvantage of this process is the cost of producing oxygen enriched air streams, which can consume a large portion of the net electric power and lead to an overall reduction in cycle efficiency (from 40 to 28% with O_2 separation processes). (Smith, 1999)

4.8.1.4 CO_2 Hydrates

The formation of stable hydrates of CO_2 has also been investigated as a CO_2 separation method, since additional synthesis gas components: hydrogen, carbon monoxide, and other trace gases are present at partial pressures too low to form hydrates. In this system, the synthesis gas is cooled and a molecular sieve removes water vapour. The gas is then cooled further and fed to a nucleation reactor, followed by a CO_2 hydrate reactor. Ocean water is used for the formation of the CO_2 hydrate slurry. The auxiliary power required to cool the gas stream to optimum hydrate formation temperatures following the nucleation reaction is much less than that required for other processes, such as physical absorption, amounting to approximately 6.1% of the net output of the plant.

4.8.1.5 Membrane Technology

Although membrane systems have been used successfully within the petroleum, natural gas, and chemical industries for many years, their application for CO_2 capture from power stations is still at the laboratory stage of development. There are two types of membrane systems, those for gas separation and those for gas absorption.

Gas separation membranes are solid membranes that operate on the principle that the porous structure permits preferential permeation of some constituents of a mixture. These systems have yet to be applied industrially for the capture of CO_2 due to the need for the flue gas to be pressurized and because of cost. Currently a 2-stage system is needed for good separation, costing double that of a conventional amine separation process.

In gas absorption, the gas diffuses through a microporous solid membrane, then is absorbed into a liquid absorbent. Gas absorption membranes are more compact than conventional membrane separators and minimize entrainment, flooding, channelling and foaming (Meisen, et al., 1997).

Although steady-state operation, no moving parts, and modular construction are attractive features of membrane systems, further development is required before they could be used on a significant scale for the capture of CO_2. The extent the cost of membrane systems could be reduced is unclear.

4.8.1.6 Cryogenic Separation

Cryogenic separation techniques offer the advantage of high recovery of CO_2, thus facilitating further use. The process involves compression and cooling of gas mixtures in several stages to liquify CO_2 and other constituents in the flue gases (Meisen, et al., 1997). The main restriction to this process is the inherently high energy requirement.

4.8.1.7 Impact of Processes on Energy Efficiency

An important aspect of CO_2 capture is the extra amount of energy required by use of separation and capture systems. The energy consumption reduces the overall efficiency of generation, typically, by 10 percentage points, which increases the amount of CO_2 that has to be captured and sequestered for the same level of electricity generation. The high cost of separating CO_2 from flue gases is a major barrier to wider use of CO_2 separation technology. Substantial reductions in these costs are needed. It is uncertain whether this can be achieved through improvement to the separation process alone. Both actual plant investigation and modelling have led to energy efficiency and CO_2 capture predictions for the application of several of the aforementioned CO_2 capture technologies and their applicability to the major fossil-fuel energy technologies described earlier in this Chapter.

4.8.2 Storage Options

4.8.2.1 Terrestrial Sequestration

Biomass or terrestrial sequestration is the use of the natural process of photosynthesis for the removal of CO_2 from the atmosphere or prevention of CO_2 emissions from terrestrial ecosystems

(Kane, 2001). CO_2 is converted by photosynthesis into biomass through fixation of carbon by vegetation. However, the collection rates are slow, and for significant capture, unrealistic amounts of land or ocean would be required (Yegulalp, et al.).

4.8.2.2 Underground Injection

Another option for storage of captured CO_2 is underground injection. Carbon dioxide can be permanently stored underground in suitable geological formations or saline reservoirs. Reinjection of acid gases (CO_2 and H_2S and other gases) into depleted gas reservoirs is already practised commercially in Canada and elsewhere in North America as an alternative to installing gas sweetening and sulphur removal processes to produce merchantable natural gas. CO_2 can also be reinjected in oil and gas reservoirs to increase recovery and production, or can be injected into deep unminable coal seams to recover coal-bed methane (Mourits, 2000).

4.8.2.3 Ocean Disposal

The ocean can be used to store CO_2. In this process, compressed carbon dioxide gas is transported by undersea pipelines, or by ship to great ocean depths. Since the compressed gas is denser than water, it is hypothesised that injected CO_2 would tend to remain on the ocean floor, slowly dissolving over time. Ocean circulation and currents would cause the stored CO_2 to gradually mix and disperse in the ocean. Table 4-7 indicates order of magnitude estimates of the percent of emitted carbon dioxide that could be stored in various types of geologic reservoirs.

4.8.2.4 Carbonate Disposal

Another theoretical disposal method suggested for CO_2 is to combine CO_2 with mineral oxides to form carbonates such as magnesite or calcite (Lackner, et al., 1998). These carbonates are environmentally safe and thermodynamically stable and, thus, can be easily stored or disposed of without consequence to the environment.

Table 4-7 CO_2 Storage Capacity of Geologic Reservoirs

Reservoir Type	Storage Option	Estimated Global Capacity	
		Gt CO_2	% of Emissions to 2050
Below Ground	Depleted oil and gas reservoirs	920	45
	Deep saline reservoirs	400-10,000	20-500
	Unminable coal reserves	>15	>1
Ocean	Deep ocean	Uncertain	

Source: (Wallace, 2000)

4.8.3 CO_2 Capture and Sequestration for Fossil Fuelled Power Plants

4.8.3.1 Coal-fired Power Facilities

Pulverized Coal

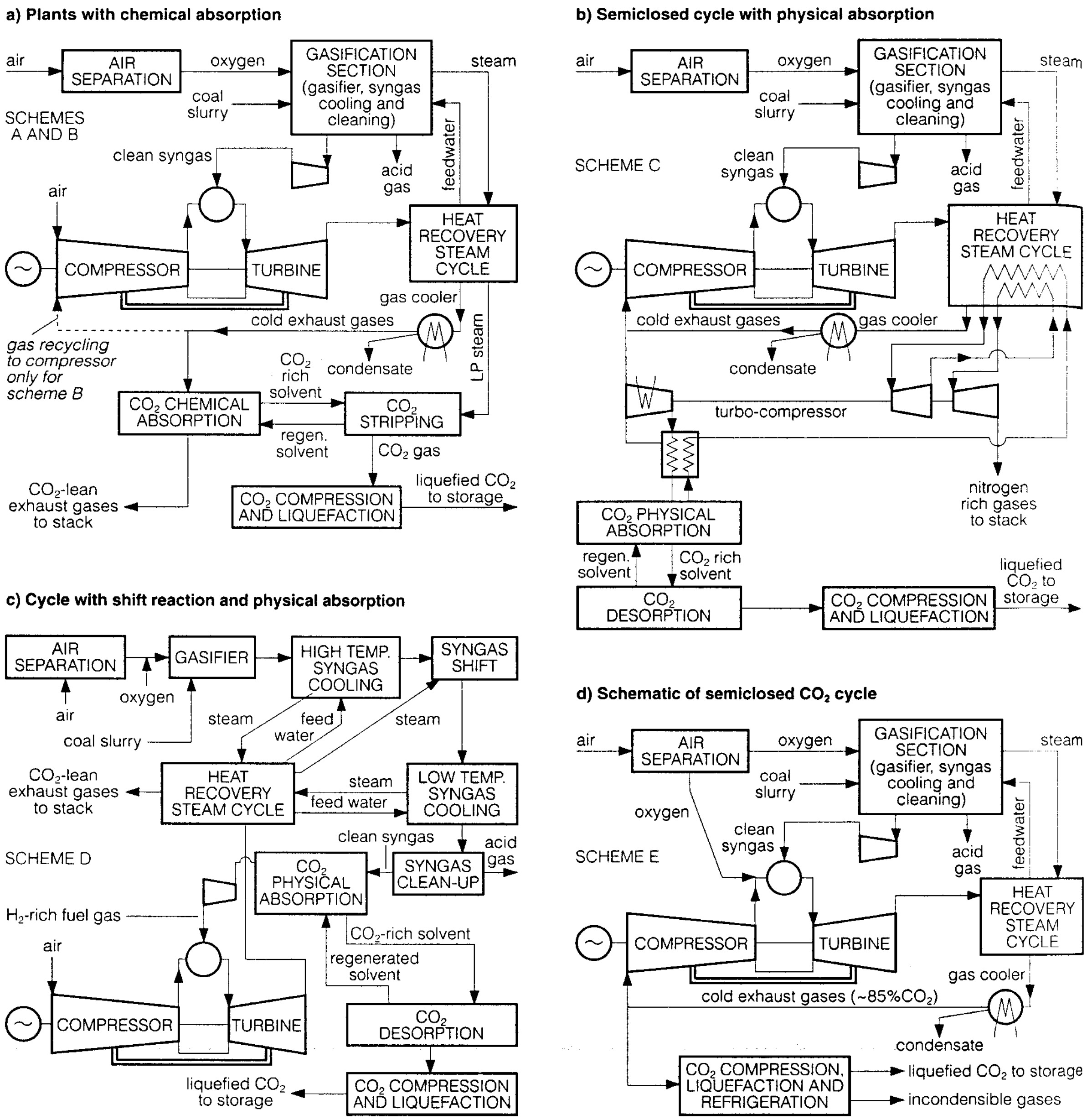
Pulverized coal firing with post-combustion flue gas desulphurisation represents the most commonly used power plant technology and a basis against which other energy technologies can be compared. The generation of power with pulverized coal technologies results in flue gases with higher CO_2 concentrations (~15% with the balance mainly N_2) than occur with oil or gas combustion. Current technologies for the capture of CO_2 are limited to the use of chemical absorption processes, principally based on monoethanol amine (MEA). Development of designer solvents is being pursued, as they can reduce regeneration energy by 30 to 40%. Research by Kiga, et al. (1995), has suggested that O_2/CO_2-blown combustion is the best option for pulverized coal-fired power plants from the viewpoint of CO_2 capture, thermal efficiency and capital cost.

Chemical absorption technology is better suited to supercritical pulverized coal power plants than subcritical pressurised fluidized bed combustion, according to work by Smith (1999). Supercritical pulverized coal plants are also candidates for use of the Selexol physical absorption process.

Integrated Gasification Combined Cycle

Design calculations and model simulations have been conducted by several researchers to estimate the energy efficiency, CO_2 removal, and costs associated with the addition of one or more CO_2 removal technologies to Integrated Gasification Combined Cycle (IGCC) power plants. Chiesa, et al. (1999) studied the five different power plant configurations shown in Figures 4-2. With a CO_2 removal efficiency of 91.5% for all of the process designs he studied, the net plant energy efficiency decreased for the base level for IGCC of 50%, to about 38% (Table 4-8). A shift reaction combined with physical absorption of syngas fuel was found to be the most appealing option for short-term implementation of low-CO_2 emission IGCC technology. Brand, et al. (1995) found that, in comparison to IGCC alone, an IGCC plant with water gas shift and physical absorption providing 88% CO_2 separation resulted in an overall plant efficiency of 39.7%, a loss of 6.5% points and a 10% increase in coal requirements compared to a plant without CO_2 removal.

Smith (1999) concluded that the best overall performance was likely to be achievable by using an O_2-blown IGCC with a water gas shift converter and CO_2 capture by high-temperature pressure swing adsorption. Table 4-9 summarizes Smith's estimates of the net power plant efficiency for various coal-fired energy technologies with and without CO_2 capture. The efficiency penalty from adding CO_2 capture technology averages in the range of 10-12% points.



Source: Chiesa, et al., 1999.

Figure 4-2 CO_2 Capture Configurations for an IGCC Power Plant

Table 4-8 Effect of CO_2 Capture on Net Efficiency of an IGCC Power Plant

Configuration	CO_2 Capture Efficiency (%)	CO_2 Separation and Compression (MW)	Net Plant Efficiency (%)
IGCC	0	0	49.95*
IGCC, with chemical absorption of CO_2 (DEA)	91.5	24.7	37.80
IGCC, with chemical absorption of CO_2 (DEA), air enriched with CO_2	91.5	23.8	38.43
IGCC, with physical absorption of CO_2 (Selexol), air enriched with CO_2	91.5	30.0	38.24
IGCC with Catalytic Shift Reaction, physical absorption (Selexol) of CO_2 from syngas	91.5	21.3	39.29
IGCC with semiclosed CO_2-H_2O cycle	91.5	31.4	38.50

Source: Chiesa, et al.,1999

* The efficiency is higher than commonly reported for this technology.

Table 4-9 Comparision of the Net Efficiency of Various Coal-fired Plant Designs with and without CO_2 Capture

Power Plant*	CO_2 Removal Options	CO_2 Capture Efficiency (%)	Net Plant Efficiency (%)	
			Base Case	After CO_2 Removal & Sequestration**
O_2-blown IGCC	Physical Absorption/SELEXOL	90	43.0	30-34
Air-blown IGCC	Physical Absorption/PSA	80	43.0	31-36
Pulverized Coal-fired Plant	Chemical Absorption/MEA	90	40.9	28-31
	O_2/CO_2 Combustion	100	40.9	28-31
PFBC	Chemical Absorption/MEA	90	41.5	29-32
Coal gasification molten carbonate fuel cell plant (MCFC)	Chemical absorption/BENFIELD	90	53.1	39-44
	Chemical absorption/MEA	90	53.1	39-44

* Gross plant output was 600 MW in all cases.

** Four storage options were considered: Deep sea injection at 3000 m depth either by pipeline or from an ocean platform receiving CO_2 by ship; and underground injection at 2000 m depth either by pipeline or from an ocean platform receiving CO_2 by ship.

Source: Smith, 1999

Electricity generation cost increases with implementation of CO_2 removal at a generation plant as a result of increased capital and operating costs. Chiesa, et al. (1999) predicted a 20-40% increase in electricity generation cost. Smith (1999) predicted that IGCC with shift conversion and syngas CO_2 scrubbing would yield the lowest cost increase, with a predicted 12% increase in the cost of electricity and a 24% increase in capital cost compared to case of the best ultra-supercritical pulverized coal plant with no CO_2 capture.

4.8.3.2 Gas-fired Power Facilities

As for coal-fired plants, CO_2 removal from gas-fired plants can be carried out by some combination of chemical absorption, oxygen-enriched air combustion, and/or decarbonisation of the fuel prior to combustion by a water-shift reaction. As shown in Table 4-10, these CO_2 removal options reduce the net plant efficiency by 8 to 13% points.

Table 4-10 Effect of CO_2 Removal on Net Efficiency of a Natural Gas-fired Power Plant

Configuration	CO_2 Capture Efficiency (%)	Net Plant Efficiency (%)
Standard combined cycle gas turbine power plant	0	58
Standard plant with chemical absorption by amine solutions	90	49.6
Combined cycle with semi-closed gas turbine and near stoichiometric combustion with oxygen	90	47.2
Decarbonisation with autothermal reforming reactor, water-shift reaction, and high pressure CO_2 removal	90	45.3

Source: Bolland, et al., 1999

4.8.4 Environmental Impacts and Uncertainties

The major impacts and uncertainties regarding CO_2 capture and sequestration, aside from optimization of plant energy efficiency and costs, are related to the final storage of the captured CO_2. These include the determination of the length of time that the captured CO_2 must remain stored in order to mitigate climate change risks, and the effects of slow or sudden release of CO_2 on atmospheric CO_2 concentrations (Wallace, 2000). Further unknowns include the total effects of the storage environment, such as the effects of drilling on the integrity of depleted oil and gas field caps and the determination of possible reactions between CO_2 and underground minerals. The suggested storage methods may also impact seismic activity or marine life.

4.9 NON-TECHNOLOGICAL OPTIONS

Regulatory and economic approaches can also lead to greenhouse gas emission reductions. This area was outside the scope of the current project and was not investigated in any detail. Some approaches that can be considered are listed below:

- Setting of air emission standards in terms of net power output rather than fuel input (or even fuel type) e.g., tonnes CO_2/GWh (plant or system basis), kg/GWh SO_2, kg/GWh NO_x, etc. A criteria or toxic emission standard per net output creates an incentive to improve energy efficiency and thereby also reduce greenhouse gas emissions.
- Applying the same emission standards regardless of fuel type, which offers some incentive to switch partly or completely to natural gas from other fossil fuels.
- Setting electricity generation standards for new and existing power plants, along with monitoring and reporting requirements, as implemented in Australia (AGO, 2000b).
- System-wide emission caps in terms of total annual tonnes CO_2, or tonnes/GWh.
- Implementation of an emissions trading system.
- Offering GHG emission credits for increased utilization of coal fly ash to displace cement in concrete and other building materials, as this can avoid substantial emissions from manufacture of cement.
- Application of carbon-based taxes to the use of fossil fuels.

A good overview of regulatory and emission-trading options for greenhouse gas emission reduction is provided in USEA, 1999.

5. ANALYSIS OF CO_2 REDUCTION OPTIONS

5.1 CO_2 EMISSION REDUCTION SCENARIOS

In order to assess the greenhouse gas (GHG) emission reduction potential for the APEC electricity generation sector, the general CO_2 reduction options in Chapter 4 were integrated into various hypothetical scenarios for application to existing plants. A variety of scenarios were selected to illustrate options of potential interest to both developed and developing economies, current and future facilities and for near term or longer term application. Scenario identifiers were assigned for ease of reference. Scenarios are grouped into four basic categories.

- Combustion, Steam Cycle, and O&M Upgrades
- Co-firing and Fuel Switching
- Repowering
- Combined Heat and Power (CHP).

Estimates of CO_2 emission reductions potentially achievable in the APEC region as a whole were developed for 1998 using data from the UDI database on the capacity of operating plants using generic energy technologies. This year was chosen because it allowed intermediate and final results of the analysis to be compared to data from independent sources. These results compared reasonably well with APEC data on installed power generating capacity, IEA data on annual electricity generation, and IEA data on carbon dioxide emissions from electricity generation. The reductions in CO_2 emissions estimated for various scenarios in this study for 1998 are indicative of the emission reductions that could potentially be achieved currently.

Estimates of CO_2 emission reductions are also presented in this Chapter on an individual basis for each emission reduction scenario to facilitate use of the information by others for individual APEC economies or power plants. The results should in these cases be adapted to reflect local conditions that may exist, with particular attention to the assumed plant efficiency values and to the economic viability of the emission reduction scenario.

5.1.1 Combustion, Steam Cycle, and O&M Improvement Scenarios

By applying combustion, steam cycle, and operating and maintenance (O&M) improvements, existing fossil fuel power plants can substantially reduce CO_2 emissions. The types of improvements that will yield cost-effective efficiency improvements are site specific, and dependent on the type of fuel and the type of existing power generation technology being used. The optimum efficiency improvement program for a power plant must be based on existing conditions and operating practices.

To investigate the potential for combustion, steam cycle and O&M improvements to significantly reduce CO_2 emissions in the APEC region, five scenarios were created using the following groupings, as summarised in Table 5-1:

Oil and gas: E1 for subcritical steam, E2 for advanced GTCC and CHP systems, and E3 for simple cycle gas turbine.

Coal: E4 for pulverized coal (PC), and E5 for combining stoker and cyclone plants.

The net plant efficiencies assumed for existing plants, as summarized in Table 5-1, are illustrative, typical annual average values. At present, comprehensive data on the net efficiency of operating plants in the APEC region are not available, so it is not possible to determine the number or capacity of plants operating in the APEC region at a net efficiency close to the values assumed for the selected technology categories. The incremental improvement in net efficiency estimated for each CO_2 reduction scenario is based on information presented in Chapter 4 and is considered to be reasonably achievable in the majority of cases. A typical, realistic package of efficiency improvements for Scenario E4 is shown in Table 5-2, though the list is not intended to be prescriptive, as there are numerous possible combinations of improvements that could be implemented to achieve a similar efficiency gain. A similar approach was used to develop the estimates of efficiency gains for the other scenarios.

5.1.2 Co-firing and Fuel Switching Scenarios

Switching to lower carbon containing fuel can be developed with two basic strategies:

1. Co-firing oil or gas at 25% for application to plants which have existing dual fuel capability:
   - E6 and E7 for oil and coal plants, respectively, which have gas fuel capability.
   - E8 for coal plants which have oil capability.
2. Switch 100% of fuel to natural gas:
   - E9 for oil plants, which presently have gas fuel capability.
   - E10 for coal plants, which presently have gas fuel capability.
   - E11 for coal plants, which presently have oil fuel capability.

Co-firing scenarios are developed as alternatives to 100% fuel switching in consideration of the additional fuel cost that may not be viable for some operations. Another critical limitation which may make co-firing more feasible is that 100% fuel switching often reduces peak capacity. Scenarios for lower carbon containing fuels are summarised in Table 5-3. The column labelled "cost category" provides a rough indication of the relative capital and operating cost of the CO_2 emission reduction option for use when comparing the full range of options considered in this study. An economic analysis should be completed to obtain reliable cost estimates for the options of interest, taking into account site-specific conditions.

Table 5-1 CO_2 Reduction Scenarios for Combustion, Steam Cycle, and O&M Improvements

ID	Applicable Fossil Fuel	Applicable Technology*	Net Efficiency of Existing Plants η**	Average Efficiency Improvement $\Delta\eta$	CO_2 Reduction	Cost Category (Low, Med, High)
E1	Oil,Gas	ST Sub	34%	2.5%	Based on efficiency gain	Low-Med
E2	Oil,Gas	GTCC & CHP	50%	2.0%	Based on efficiency gain	Low-Med
E3	Oil,Gas	SC	26%	5.0%	Based on efficiency gain	Low-Med
E4	Coal	PC Sub, PC Super	34%	3.5%	Based on efficiency gain	Low-Med
E5	Coal	Stk/Cyc	30%	3.5%	Based on efficiency gain	Low-Med

* See definition of acronyms and abbreviations at the beginning of this report.
** Energy efficiency based on lower fuel heating value.

Table 5-2 Illustration of Efficiency Improvement Package for Scenario E4

	Improvement	Net Efficiency Gain (% points)
Combustion System	Pulverizer and feeder upgrades	0.30
	Air preheater repair or upgrade	0.25
	Sootblower improvements	0.35
	Excess air I&C	0.20
Steam Cycle	Feedwater heater repairs	0.40
	Heat transfer tube upgrades	0.60
	Steam turbine blades	0.50
	Cycle isolation program	0.50
	Condenser repairs	0.40
O&M	O&M training	Included in combustion and steam cycle gains. Efficient operation realized over the long term.
	CMMS and RCM	
	DES upgrade	
	Artificial intelligence based software (includes OPM)	
Combined Total		3.5

Table 5-3 CO_2 Reduction Scenarios for Lower Carbon Containing Fossil Fuels

ID	Scenario Description	Applicable Fossil Fuel	Applicable Technology*	CO_2 Reduction	Cost Category (Low, Med, High)
E6	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Oil	ST Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med
E7	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Coal	PC Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med
E8	Co-fire Boiler with 25% Oil: apply to all existing plants with oil capability	Coal	PC Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med
E9	Fuel Switch to 100% Gas: apply to all existing plants with gas capability	Oil	ST Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med-High
E10	Fuel Switch to 100% Gas: apply to all existing plants with gas capability	Coal	PC Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med-High
E11	Fuel Switch to 100% Oil: apply to all existing plants with oil capability	Coal	PC Sub	Based on % of lower carbon fuel. Assume no change in efficiency	Med-High

* See definition of acronyms and abbreviations at the beginning of this report.

5.1.3 Repowering Scenarios

Repowering scenarios are created with the highest efficiency technologies and use of biomass, as summarised in Table 5-4.

Repowering scenarios for existing oil and gas plants include:

- E12 and E13 for repowering with gas-fired GTCC technology
- E18 for repowering with CHP.

Repowering scenarios for coal-fired facilities include:

- E14 with supercritical technology
- E15 with AFBC technology and 20% biomass, and scenario E16 with 100% biomass
- E17 for repowering with developing technologies IGCC or PFBCC.
- E19 for repowering with CHP

Table 5-4 CO_2 Reduction Scenarios for Repowering with more Advanced Technologies

ID	Scenario Description	Applicable Fossil Fuel	Applicable Technology*	Net Efficiency of Existing Plants η_1	Net Efficiency of Upgraded Plants η_2	CO_2 Reduction	Cost Category (Low, Med, High)
E12	Repower with GTCC	Oil,Gas	ST Sub	34%	55%	Based on efficiency gain	High
E13	Repower with GTCC	Oil,Gas	SC	26%	55%	Based on efficiency gain	High
E14	Repower with PC Super	Coal	PC Sub	33%	42%	Based on efficiency gain	High
E15	Repower with AFBC and 20% Biomass	Coal	PC Sub, Stk/Cyc	33%	38%	Based on efficiency gain plus 20% biomass credit	High
E16	Repower with AFBC and 100% Biomass	Coal	PC Sub, Stk/Cyc	33%	38%	100 reduction based on biomass	High
E17	Repower with IGCC or PFBCC	Coal	PC Sub, Stk/Cyc	33%	45%	Based on efficiency gain	High
E18	Repower with CHP	Oil,Gas	ST Sub	49%	75%	Based on efficiency gain	High
E19	Repower with CHP	Coal	PC Sub	49%	75%	Based on efficiency gain	High

* See definition of acronyms and abbreviations at the beginning of this report.

Repowering with biomass involves challenges with fuel production, transport, and on-site materials handling that affect the viability of large biomass-fuelled electricity generating plants. As a result of these challenges, a substantial increase in biomass use for electricity generation in the APEC region is considered a long-term future scenario. The IPCC (2001a) estimates with an 80% probability that up to a 73 Mt reduction in CO_2 emissions can be achieved by 2010 through substitution of biomass for coal. This mitigation measure is estimated to have a cost of -US$5 to +US$30 per tonne of CO_2 reduced. The IPCC estimates that by 2020, use of biomass fuel could yield a reduction of 180-360 Mt CO_2.

The efficiency of existing plants is the assumed average annual efficiency for all scenarios based on the type of technology employed. For CHP, it is necessary in this analysis to calculate a combined efficiency of separately generated heat and power, $\eta_{combined}$. The following formula is used (El-Wakil, 1984) to calculate the net efficiency of the existing plants for E19, $\eta_{combined}$, at 49%. The approach calculates the combined efficiency based on the ratio of useable electricity and heat energy to the total input energy for electricity and heat generation, assuming typical efficiencies for the separate energy facilities and a typical ratio of electricity to the total heat and electric load. Electricity is assumed to be generated at a 33% efficiency, while heat is assumed to be generated at 80% efficiency. After repowering, CHP is assumed to be provided at a moderate efficiency of 75%.

$\eta_{combined} = [\, e / \eta_e + (1-e) / \eta_h \,]^{-1}$ where:

$\eta_{combined}$ = combined efficiency of separately generated electricity and heat

η_e = efficiency of electrical generation

e = ratio of electrical energy to total (heat plus electricity) energy

e is estimated to be η_e / η_{cogen} where $\eta_{cogen} = 0.75$ thus, e = 0.44

η_h = efficiency of heat production, assumed to be 0.80

5.2 Methodology of Assessing CO_2 Emission Reduction Scenarios

The analysis is intended to yield realistic order-of-magnitude estimates of CO_2 emission reduction options for fossil fuel power plants for the purpose of assisting in the screening of a number of alternatives potentially suited to the APEC region. Further more detailed analysis would be required to evaluate the technical and economic feasibility of an identified CO_2 option for application at a specific facility in a specific APEC economy. The viability of each strategy is substantially dependent on the type of technology presently in place. Therefore it became necessary to estimate CO_2 emissions attributable not only to type of fossil fuel, but also to the type of technology. This presented a challenge since available studies and literature provide a wealth of information on power generation and CO_2 emissions broken down by fuel, but not further broken down by technology.

Data on the size and technology type for all of the power plants listed in the UDI database were used for the analysis. The version of the database obtained for the study contains data on power plants updated to November, 2000. A subset of this data, including all operating power plants as of 1998, was used in the study as this provided reasonably current estimates, while also enabling comparisons to be made between the data for generating capacity, electricity generation and greenhouse gas emissions used in this study and values reported in other data sources. These comparisons are explained in the following sections and agree reasonably well for the APEC region. The results of the analysis are summarised in Table 5-5.

5.2.1 Estimating MW Capacity by Technology Groups

The first step in estimating CO_2 emissions by technology was to estimate the MW capacity of plants for each technology group. The UDI database of plants for all APEC economies was analysed in detail in order to assign every plant in the database to a technology category and to extract data for all operating plants as of 1998.

The information needed to assign a technology category was available for many plants, but for a substantial number of plants this had to be inferred from other information available in the database. Table 5-5 summarizes the MW capacity and number of plants for gas, oil and coal fired facilities in the APEC region operating in 1998 (see also Table 3-7 in Chapter 3 for the distribution of capacity by technology group and fuel within each APEC economy up to November, 2000). The total MW of thermal generating capacity used for the analysis in this study is 4% below the value reported by the APEC economies for 1998 (APEC, 2001).

5.2.2 Estimating kWh by Technology Groups

The next step in the analysis was to estimate TWh of electricity generation for each technology group. In order to accomplish this task, capacity factors were assumed as shown in Table 5-5, with newer and higher-efficiency plants considered to have higher capacity factors. With the assumed capacity factors, the equivalent operating hours per year (i.e., equivalent hours operating at full load) were calculated and used along with plant capacity to determine TWh of generation. The TWh subtotals by technology group for each fossil fuel were then summed and these values were compared to the totals reported by the IEA for the APEC region for 1998. (see Appendix B for tabulated IEA data).

The estimated total TWh of electricity generation for natural gas, oil and coal in this study are compared to IEA statistics in Table 5-5 and show the values estimated in this study, with the assumed capacity factors, are 21.9% higher for natural gas, 15.8% higher for oil, and 2% lower for coal. The TWh electricity generation data for this study are reasonably close to IEA statistics considering the uncertainty in the data sets and the assumed nominal capacity factors. Because the estimate of TWh of electricity generation is only an intermediate step in estimating CO_2 emissions for each technology group and fossil fuel, the observed differences do not preclude completing this analysis. However, a potential area for future study by APEC would be to compile a more accurate data set for the TWh of electricity generation for each technology group in each APEC economy.

5.2.3 Estimating Fuel Fired by Technology Group

Converting TWh of electricity generation to input fuel is a matter of knowing the average annual efficiency. These efficiencies are not readily available for technology groups in the APEC region and, hence, realistic values were assumed as shown in Table 5-5.

It should be emphasised that these LHV efficiencies should be representative of annual average efficiency, including the inefficiencies associated with startup, shutdown, and reduced load operations. Hence, these efficiencies will always be lower than the full-load design efficiency for the technology. For example, existing PC subcritical steam plants typically can operate at 36% efficiency. However, an efficiency of 33%, a reduction of 3% points, is assumed as the average annual efficiency for all APEC plants. Results of the survey were also considered in assigning these efficiency values. The analysis could be improved in future as improved data becomes available on the average efficiency of each type of in-use energy technology, for each type of fuel used.

5.2.4 Estimating CO_2 Emissions by Technology Group

The final step necessary to estimate CO_2 emissions by technology group was to use average emission factors as shown in Table 5-5 to calculate emissions on the basis of the input fuel energy. This produced an estimate of the CO_2 emitted per year attributable to each technology group.

To cross-check the CO_2 emission results, emissions from all technology groups for each fossil fuel were summed and compared to the 1998 CO_2 emissions reported by the IEA for electricity and heat generation, as discussed in Chapter 3 of this study. The resulting difference is shown in Table 5-5. Compared to IEA estimates of CO_2 emissions from electricity and heat production by public and autoproducers, the CO_2 emission estimates in this study are 7.6% lower for natural gas, 5.3% higher for oil, 6.7% lower for coal and 5.6% lower for total thermal generation. Although these comparative results do not guarantee the accuracy of the CO_2 emission estimates by energy technology, they do indicate that the UDI plant capacity data and the assumptions made for capacity factor and net efficiency are sufficiently reliable for making order-of-magnitude estimates of CO_2 emission reductions possible in the APEC region by application of the scenarios described in Section 5.1.

5.2.5 Estimating Emissions of CO_2 For Each Reduction Scenario

Section 5.1 defines the CO_2 emission reduction basis for each scenario (i.e., efficiency improvement and/or fuel-related) as applied to a given type of plant. Sections 5.2.1 to 5.2.4 define the pool of potential candidate plants for each scenario in terms of the number of plants, total MW and current emissions of CO_2. The final step necessary to estimate the CO_2 reduction for each scenario is to make reasonable assumptions regarding how many plants, or what percentage of the available generating capacity, to which the scenario could be applied. With this assumption made, the baseline CO_2 emissions were used to calculate an approximate reduction that could potentially be achieved.

For example, scenario E1 is defined in Section 5.1.1 to apply to subcritical steam turbine technology for gas and oil plants. Table 5-5 shows that in 1998 there were 289,149 MW of capacity (164,033 MW gas plus 125,116 MW oil) and 2,177 plants (1,301 for natural gas, plus 876 for oil). CO_2 emissions in 1998 were estimated to be 770 Mt of CO_2 for these technology groups (426 Mt from gas, plus 344 Mt from oil). It was not deemed to be reasonable that 100% of the identified power plants could be upgraded throughout the APEC region. Hence, a realistic, yet arbitrary assumption was made that 50% of the plants would be included in the application of scenario E1. This translates to 50% of the CO_2 emissions are potentially available for reduction by EI, for a total of 385 Mt of CO_2. Assumptions for all five Combustion, Steam Cycle, and O&M scenarios are summarised in Table 5-6.

Table 5-5 Estimated CO_2 Emissions by Technology Group for APEC Fossil Fuel Generation Based on UDI Database through 1998

Fuel	Technology Group	No. of Plants	Operating Plants* (MW)	Plant Average Size (MW)	Assumed Capacity Factor	Calculated Annual Hours Operating	Calculated (TWh)	IEA Data (TWh)	Difference in TWh (%)	Assumed LHV Efficiency of Existing Plants (%)	Calculated Fuel Fired (TJ)	Average CO_2 Emission Factor ($t\ CO_2 / TJ_{in}$)	Calculated CO_2 Emission (Mt)	IEA CO_2 Emission (Mt)	Difference in CO_2 Emission (%)
Gas	CC or CHP	3,454	86,250	25	70%	6,132	529	--	--	50%	3,807,969	56	213	--	--
	ST Super	118	64,823	549	70%	6,132	397	--	--	40%	3,577,468	56	200	--	--
	ST Sub	1,301	164,033	126	50%	4,380	718	--	--	34%	7,607,249	56	426	--	--
	SC	1,776	51,907	29	10%	876	45	--	--	26%	629,596	56	35	--	--
	Total/Ave	**6,649**	**367,013**				**1,690**	**1,387**	**+21.9**		**15,622,283**	**56**	**875**	**947**	**-7.6**
Oil	CC or CHP	2,249	24,596	11	70%	6,132	151	--	--	50%	1,085,919	74	80	--	--
	ST Super	53	29,535	557	70%	6,132	181	--	--	40%	1,629,956	74	121	--	--
	ST Sub	876	125,116	143	40%	3,504	438	--	--	34%	4,641,953	74	344	--	--
	SC	8,196	67,155	8	10%	876	59	--	--	26%	814,539	74	60	--	--
	Total/Ave	**11,374**	**246,402**				**829**	**716**	**+15.8**		**8,172,366**	**74**	**605**	**574**	**5.3**
Coal	AFBC	121	6,832	56	70%	6,132	42	--	--	38%	396,898	110	44	--	--
	PC Super	170	117,489	691	70%	6,132	720	--	--	39%	6,650,216	95	632	--	--
	PC Sub	2,580	492,920	191	65%	5,694	2,807	--	--	33%	30,618,407	95	2,909	--	--
	Stk/Cyc	444	33,653	76	35%	3,066	103	--	--	30%	1,238,150	95	118	--	--
	Total/Ave	**3,315**	**650,894**				**3,672**	**3,748**	**-2.0**		**38,903,671**	**99**	**3,702**	**3,967**	**-6.7**
Total Thermal	**Total**	**21,338**	**1,264,308**	**59**	**-**	**-**	**6,191**	**5,851**	**+5.8%**	**-**	**62,698,320**	**-**	**5,182**	**5,488**	**-5.6**

* See Table 3-7 in Chapter 3 for a detailed breakdown of the existing generating capacity for each technology in the APEC economies to November, 2000.

Table 5-6 Emission Basis for Assessing Effects of Scenarios E1 to E5 in 1998

ID	Fossil Fuel	Applicable Technology	CO_2 Emissions (Mt)	Existing Capacity of Applicable Technology (MW)	Scenario Application Percentage (%)	Number of Plants for Scenario Application	Capacity of Plants for Scenario Application (MW)	CO_2 Emissions from Plants for Scenario Application (Mt)
E1	Oil,Gas	ST Sub	770	289,149	50.0	1,089	144,574	385
E2	Oil,Gas	GTCC & CHP	294	110,846	50.0	2,852	55,423	147
E3	Oil,Gas	SC	96	119,062	50.0	4,986	59,531	48
E4	Coal	PC Sub, PC Super	3,541	610,409	50.0	1,375	305,204	1,770
E5	Coal	Stk/Cyc	118	33,653	50.0	222	16,826	59

The scenario application percentages are nominal values chosen by judgement considering the total capacity of plants using the applicable technology, the changes needed to implement the scenario, and a reasonable level of penetration of the scenario over a prolonged period. The capacity of plants included in the application of Scenario E1, E2 and E3 is substantially less than the aggregate capacity of gas and oil fired plants over 15 years old (see Figure 3-9 for age profile). Similarly, the capacity of coal fired plants considered for application of E4 is less than the aggregate capacity of plants greater than 15 years old that are using the applicable technology.

For co-firing and fuel switching scenarios, the UDI database was first sorted by technology groups (see Section 5.2.1) then further sorted by using the "ALTFUEL" field, which indicates that fuel supply equipment exists to fire an alternative fuel. It has been assumed that an indication of alternative fuel firing capability also means that a supply of this alternative fuel is available, or could be made available, to enable fuel switching at the plant. Coal plants for each category were further sorted to determine the number and MW capacity of plants capable of firing gas and oil. A percentage of the total number of plants was then calculated, and this percentage was used to estimate the emissions of CO_2 potentially available for reduction using a scenario.

Using scenario E6 as an example, analysis of the complete list of oil-fired subcritical steam turbine plants in the UDI database for APEC economies revealed that 28.7% have gas as the primary alternative fuel. This percentage was applied to the total number and capacity of applicable technology plants for scenario E6, leading to an estimate of 147 plants and 35,908 MW having gas as the primary alternate fuel in that oil-fired technology group. Hence, it was estimated that 28.7% of the 344 Mt of CO_2, or 99 Mt of CO_2 would be available for potential reduction by scenario E6 according to the reduction basis for this scenario. The results of this exercise for the five co-firing and fuel switching scenarios are shown in the Table 5-7.

Table 5-7 Basis for Assessing Effects of Scenarios E6 to E11 in 1998

ID	Scenario	Fossil Fuel	Applicable Technology Categories	CO_2 Emissions (Mt)	Existing Capacity of Applicable Technology (MW)	Scenario Application Percentage (%)	Number of Plants for Scenario Application	Capacity of Plants for Scenario Application (MW)	CO_2 Emissions from Plants for Scenario Application (Mt)
E6	Co-fire boiler with 25% gas: apply to plants with gas capability	Oil	ST Sub	344	125,116	28.7	147	35,908	99
E7	Co-fire boiler with 25% gas: apply to plants with gas capability	Coal	PC Sub	2,909	492,920	6.1	189	30,068	177
E8	Co-fire boiler with 25% oil: apply to plants with oil capability	Coal	PC Sub	2,909	492,920	8.2	295	40,419	239
E9	Fuel switch to gas: apply to plants with gas capability	Oil	ST Sub	344	125,116	28.7	147	35,908	99
E10	Fuel Switch to Gas: apply to plants with gas capability	Coal	PC Sub	2,909	492,920	6.1	189	30,068	177
E11	Fuel Switch to Oil: apply to plants with oil capability	Coal	PC Sub	2,909	492,920	8.2	295	40,419	239

For repowering, the percentage of plant capacity (or CO_2 emissions) to include in the application of the scenario in the APEC region was made based on the commercial viability of the technology and widespread availability of the fuel. These results are included in Table 5-8. For example, a large percentage of plant capacity (e.g., 20% for E12, or 58 GW) was assumed for GTCC technology. A smaller capacity was assumed for scenario E17 since IGCC and PFBCC technologies are still being developed/commercialized for widespread use. CHP would ideally be applied to a very large portion of plant capacity. Due to the challenges in matching electricity and heat demands at a given location, a modest percentage of plant capacity has been assumed for CHP scenarios E18 and E19.

To check the reasonableness of the assumed penetration levels of the CO_2 emission reduction scenarios for repowering, they were checked against the capacity of older plants in the APEC region. This review indicated that there is over 150,000 MW of coal-fired plants over 30 years old that would be potentially attractive candidates for Scenarios E14-E17 and E19. There is over 130,000 MW of capacity of gas and oil-fired plants greater than 30 years old that would be potentially attractive candidates for Scenarios E12, E13 and E18.

Table 5-8 Basis for Assessing Effects of Scenarios E12 to E19 in 1998

ID	Scenario	Fossil Fuel	Applicable Technology Categories	CO_2 Emissions (Mt)	Existing Capacity of Applicable Technology (MW)	Scenario Application Percentage (%)	Capacity of Plants for Scenario Application (MW)	CO_2 Emissions from Plants for Scenario Application, (Mt)
E12	Repower with GTCC	Oil Gas	ST Sub	770	289,149	20.0	57,830	154
E13	Repower with GTCC	Oil Gas	SC	96	119,062	40.0	47,625	38
E14	Repower with PC Super	Coal	PC Sub	2,909	492,920	10.0	49,292	291
E15	Repower with AFBC and 20% Biomass	Coal	PC Sub, Stk/Cyc	3,026	526,573	10.0	52,657	303
E16	Repower with AFBC and 100% Biomass	Coal	PC Sub, Stk/Cyc	3,026	526,573	5.0	26,329	151
E17	Repower with IGCC or PFBCC	Coal	PC Sub, Stk/Cyc	3,026	526,573	5.0	26,329	151
E18	Repower with CHP	Oil Gas	ST Sub	770	289,149	5.0	14,457	38
E19	Repower with CHP	Coal	PC Sub	2,909	492,920	5.0	24,646	145

5.3 ESTIMATED CO_2 EMISSION REDUCTION POTENTIAL FOR SCENARIOS

5.3.1 Emission Reduction for Facilities in the APEC Region

The CO_2 reduction formulas for each scenario were multiplied by the estimated 1998 CO_2 emissions for the applicable facilities discussed in Section 5.2.5. This produced an order-of-magnitude estimate of CO_2 emission reductions for all 19 scenarios in 1998, based on the existing population of power plants operating in that year. These results are summarised in Figure 5-1, and in a detailed table of results included in Appendix E.

As previously stated, these calculated emission results should be considered of order-of-magnitude accuracy. Nonetheless, since the calculations are based on a "ground up" analysis taking into account the best available information on APEC power plant technologies, the accuracy is considerably better than possible with estimates based solely on CO_2 emissions and fuel data. The CO_2 emission reduction estimates are satisfactory for identifying the more promising strategies and for identifying those that need closer consideration for specific APEC economies or throughout the APEC region. The relative magnitude of the CO_2 emission reductions possible by application of the scenarios in the APEC region suggest relative priorities for policy making and in pursuing specific CO_2 emission reduction programs. Before proceeding with implementation of one of the identified CO_2 emission reduction scenarios in an APEC economy, analysis should be done to determine the cost effectiveness of the scenario and to identify constraints that may exist, such as availability of fuels for fuel switching options.

A brief discussion of results follows in the next section for each group of scenarios.

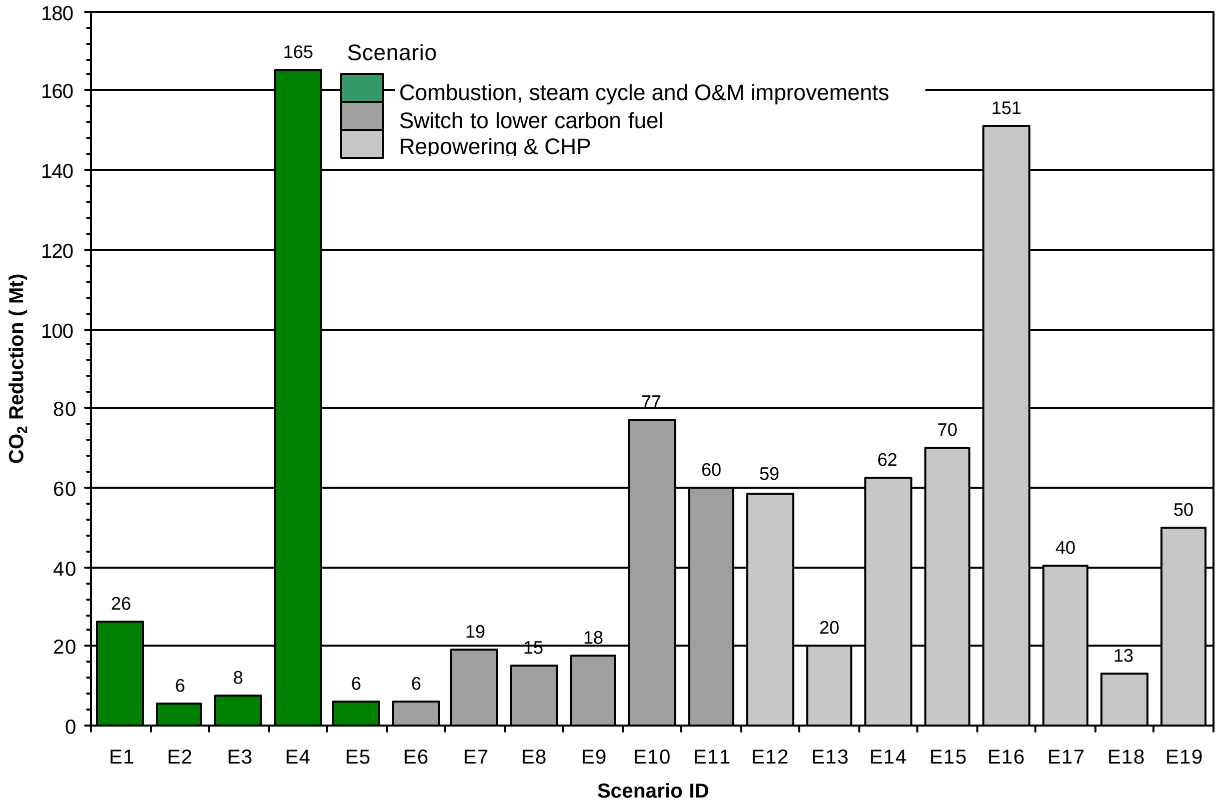


Figure 5-1 CO_2 Emission Reduction in the APEC Region Based on an Assumed Level of Implementation of the Scenarios to Existing Power Plants in 1998

5.3.1.1 Combustion, Steam Cycle, and O&M Improvement Scenarios (E1-E5)

Amongst the five combustion, steam cycle, and O&M improvement scenarios, E4 is the most promising. The estimated CO_2 emission reduction in the APEC region of 165 Mt of CO_2 is a large number. This is roughly equal to all of Australia's power sector CO_2 emissions in 1998 (Appendix B), which is the fifth largest emitter in APEC. While no detailed cost data was obtained in the literature, the experience of the authors is that an approximate range of $1-$10 U.S. per kW capacity would apply, depending on many factors such as plant size and extent of upgrades needed to achieve optimum efficiency of PC power plants. For example, a 300 MW plant would have a budget range of US$300,000 to US$3,000,000 for such upgrades. With this cost range and size of plant, the cost effectiveness of CO_2 emission reduction varies from about US$2 to US$18 per tonne of CO_2 reduced. Based on the E4 scenario assumption of targeting 50% of the PC subcritical and supercritical generating capacity, there was approximately 305 GW in 1998 that could potentially use scenario E4. The current combined capacity targeted by E4 will have grown slightly since 1998.

Scenario E1 (gas and oil subcritical steam plants) is also an attractive option in that it shows a potential reduction of 26 Mt of CO_2, and could be accomplished less expensively than upgrading PC power plants.

Because of the relatively low CO_2 reduction estimates, scenarios E2, E3, and E5 are not indicated to be cornerstone strategies in establishing policies for achieving CO_2 emission reductions.

5.3.1.2 Co-firing and Fuel Switching Scenarios (E6-E11)

Amongst the three 25% co-firing scenarios (E6-E8), E7 (co-fire gas in PC subcritical plants) is the most attractive. It is estimated that 19 Mt of CO_2 could be reduced in APEC economies by co-firing gas at 25% of fuel input at 189 plants in 1998, assuming circumstances permit firing the additional quantity of natural gas economically. As these plants are indicated to presently have gas-firing capability, the capital cost should be low. Operating cost would increase due to the fuel cost differential, which would need to be examined on a site-specific basis.

Similarly for the 100% fuel switching scenarios, E10 is the most attractive with an estimated CO_2 emission reduction of 77 Mt of CO_2. Different percentages of co-firing can easily be interpolated from these results. For example, co-firing 50% gas would produce a 39 Mt CO_2 reduction.

5.3.1.3 Repowering Scenarios (E12-E19)

The repowering scenarios E12 to E19 are estimated to reduce CO_2 emissions in the range of 13 to 151 Mt of CO_2. As such, every repowering scenario presented is potentially attractive depending on economy-specific circumstances such as availability of capital funds and access to alternate fuels. With the exception of scenario E17, repowering with IGCC or PFBCC, all repowering scenarios are based on technologies that are commercial and widely available in APEC. The viability of biomass repowering is very site specific and fuel supply and transportation will limit the scale of application at an individual site. Studies by the IPCC (2001a) suggest continued growth in biomass fuel use and displacement of some fossil fuels, with significant reductions in CO_2 emissions by 2010 and 2020. The technical and economic feasibility of these technologies in a particular economy will depend on local factors and would need to be examined in detail.

5.3.2 Promising Options for the Top Five CO_2 Emitting APEC Economies

The results in Section 5.3.1 are for APEC as a whole. This section contains a discussion of the most promising scenarios as applied to the economies in APEC having the top five annual CO_2 emissions from the electricity generation sector. These economies are listed in Table 5-9.

Table 5-9 CO_2 Emissions from Combustion of Fossil Fuels for Electricity Generation for the Five Largest CO_2 Emitting Economies in 1998

Economy	Coal-Fired ($Mt\ CO_2$)	Oil-Fired ($Mt\ CO_2$)	Gas-Fired ($Mt\ CO_2$)	Total ($Mt\ CO_2$)	Emissions as Percent of U.S.
United States	1,920	123	332	2,375	100%
PR China	1,081	60	5	1,146	48%
Russia	249	107	387	743	31%
Japan	186	98	96	379	16%
Australia	154	2	8	164	7%

5.3.2.1 United States

The United States has 48% of existing generating capacity fired using pulverized coal, which is roughly half of the 610 GW in all of APEC region in 1998; the capacity in the UDI database to November, 2000 is 630 GW. As such, roughly half of the CO_2 emission reductions for scenarios E4, E7, and E8 would occur in the United States. Similarly, the United States possesses one-third of the oil-fired and nearly half of the gas-fired subcritical plants in all APEC. Therefore, scenario E1 and the repowering scenarios demonstrate good potential for application in the United States. With the United States being heavily weighted in coal-fired power, an emphasis on fuel switching for existing and repowered plants appears to be promising approaches to achieve reductions in CO_2 emissions.

5.3.2.2 China

China's coal-fired CO_2 emissions are half the emissions of the United States, hence emphasis on scenario E4 (efficiency improvements) demonstrates good potential. China reportedly has widespread challenges in firing slagging coals that were not designed for the boilers in the original design and in phase-out of old inefficient subcritical plants. The combustion system upgrades that can improve efficiency can simultaneously be applied to enable better combustion of slagging coals (e.g., sootblower upgrades, pulverizer improvements, air distribution, etc.). Relative to coal, China's utilisation of gas for power generation is very low. As such, emphasis on fuel switching (i.e., scenario E10) and repowering with GTCC technology would be effective.

There is also good potential for greater application of cogeneration of heat and power in many large industrial operations. The World Bank identified the iron and steel, pulp and paper and textiles industries as ones likely to be able to make better use of cogeneration technologies (World Bank, 1996).

In 1996, the IEA identified a range of potential projects for implementation in China and India (IEA, 1996) that are similar to those considered independently in this study. The IEA project suggestions and the potential benefits that were expected to result are summarized below:

Project Type	Potential Benefits
• replace small units with one large unit >300MW.	• reduce CO_2 25% and reduce NO_x, SO_x and particulate emissions.
• upgrade efficiency of large new domestic units.	• reduce CO_2 10% and reduce NO_x, SO_x and particulate emissions.
• upgrade auxiliary equipment for large power units.	• reduce CO_2 10% and reduce NO_x, SO_x and particulate emissions
• repower old and new units with CHP.	• reduce CO_2 50-80% and reduce NO_x, SO_x and particulate emissions.
• introduce clean coal technologies.	• reduce CO_2 20-60% and reduce NO_x, SO_x and particulate emissions 80%.
• renovate old units.	• reduce CO_2 10-60% and reduce NO_x, SO_x and particulate emissions.

Zhou (1999) lists measures for improving the efficiency of electricity use and electricity generation in China. By implementation of these measures, Zhou (1999) projects that the average efficiency of power generation from coal in China is anticipated to improve from 33.5%

in 1995 to 35.5% in 2010 (based on other data, these values presumably apply to coal-fired power plants over 300 MW). Hao (2001) indicates that coal-fired power plants in China of under 50 MW capacity typically have a net plant efficiency of less than 30% (LHV), while plants with capacities over 300 MW typically have an efficiency of about 33-34%. The report on the electric power industry for 2000 by the China Electric Power Information Center (2000) indicates that the net efficiency of all thermal power plants over 6 MW in capacity in 1999 was 30.8%, increased slightly from an average of 30.4% in 1998. About 92% of the thermal generating capacity is coal-fired and 47.3% is below 200 MW capacity, 38.8% is of 200-300 MW capacity and 13.9% is over 300 MW capacity. Consequently, the higher efficiency plants make up a small percentage of the total thermal generating capacity. A recent study by the IEA (2001) indicates that the average thermal efficiency of coal-fired power plants in China is 27-29%, which is somewhat lower than the average referred to above from the China Electric Power Information Center (2000).

The measures identified by Zhou (1999) to achieve improvement in the efficiency of coal-fired power plants in China through to 2010 include O&M improvements, installation of CHP and repowering, as follows:

- build larger units;
- replace medium and small units (many plants under 50 MW have recently been shut down);
- use generation units in service for other purposes;
- cogeneration of heat and power;
- reduce power consumption by ancillary plant equipment;
- decrease the power loss from power lines in the distribution system.

Discussions with Jiming Hao (2001) of Tsinghua University, Cheng Xiahong (2001) of the State Power Corporation of China and the Thermal Power Research Institute (TPRI) of the State Power Corporation of China identified the following options of most interest for improving the efficiency of coal-fired power plants in PR China:

- shutdown small plants;
- retrofit more efficient steam turbine blades or replace old steam turbines with more efficient equipment;
- improve efficiencies of pumps and blowers;
- reduce power plant’s own use of electricity below a typical current level of 8%;
- improve coal pulverizer performance and reduce particle size;
- improve control of excess air levels in the furnace and of the combustion process;
- improve the steam cycle, reduce flue gas heat loss, reduce tramp air;
- improve firing conditions for slagging coals;
- improve the efficiency of large plants using supercritical and ultra supercritical steam pressures;
- install CHP facilities for use of waste heat, including district heating opportunities, as many power plants are close to urban areas;
- conduct energy audits of power plants;
- demonstrate the application of IGCC technology.

Natural gas GTCC power plants were also identified as having potential on the coast of China in areas near urban areas where natural gas pipelines will be constructed. Because of the higher cost of natural gas compared to coal, its use will be generally limited to supply of peaking capacity.

Improving generation efficiency and energy conservation were concluded to be China's least-cost option for increasing power supply in a study of China's electric power options (Battelle, et al., 1998). This study forecast regional electricity demand through to 2020 and, using a linear programming model, determined the least-cost combination of technologies to meet this electric power demand and reduce environmental effects from the power sector. The study also concluded that increased use of natural gas combined cycle technology for power generation was the lowest cost option to reduce carbon dioxide emissions by 2020, assuming a maximum gas price of US$3.10/GJ. The penetration of this technology was found to be sensitive to natural gas pricing, which is uncertain, and to be constrained over the short term by the limited availability of natural gas. The high capital cost of IGCC and PFBC technologies were concluded to be a significant impediment to greater use of these clean coal technologies compared to natural gas fired combined cycle technology.

5.3.2.3 Russia and Japan

Relative to the United States and China, Russia and Japan's power sectors are well balanced in fossil fuel utilisation. As such the efficiency improvement scenarios E1 and E4 would be most effective in reducing CO_2 emissions in these two economies. Russia also possesses excellent gas supplies, and hence has the ability to focus on repowering plants with inexpensive GTCC technology on a more widespread basis. Japan, on the other hand, does not possess the gas resources and depends more on LNG imports. As such, Japan has less economic incentives to make large increases in gas utilisation, which would make high-efficiency coal technology, such as scenarios E14 and E17, more attractive.

A study completed in 1995 for the U.S. Department of Energy (All-Russian Thermal Engineering Institute, 1995) reviewed the power industry and the use of advanced coal-fired technologies in Russia and examined interests in, and opportunities for, application of U.S. clean coal technologies in Russia. From the results of this study, it is evident that there are opportunities for application of combustion, steam cycle and O&M efficiency improvements, for repowering with advanced clean coal technologies (for high-ash coals) and for improved cogeneration systems, and for fuel switching to natural gas. Russian thermal coals tend to be used as-mined and to have high ash contents. Large amounts of brown coals are used, which are prone to slagging problems. The efficiency of coal-fired condensing power plants ranges from 34-35% for 150 MW capacity units to 36.2-36.9% for 500 MW capacity units. The annual net efficiency of the best coal-fired supercritical power plant is reported to be 37%. Many of the thermal power plants in Russia are old and potential candidates for application of more efficient and lower emitting circulating fluid bed technology. This technology was indicated to be attractive for these existing plants as it could be adapted to fit within the limited available space. Over one-half of all fossil-fuelled thermal power plants cogenerate heat for district heating systems in urban areas and for industrial applications. IGCC technology was concluded to be attractive for large future coal-fired power plants and there is interest in technology transfer with the U.S. to apply this technology in Russia over the next 10 years.

5.3.2.4 Australia

Australia's CO_2 emissions are almost exclusively attributable to coal-fired power plants. Therefore the efficiency improvements in scenario E4 would be effective in reducing its CO_2 emissions. With this level of coal utilisation, an emphasis on high-efficiency coal technology such as scenario E14 would be effective. To the extent possible, employment of fuel switching to gas or oil would reduce Australia's CO_2 emissions substantially.

Australia has implemented a program to improve the efficiency of electricity generation and achieve CO_2 emission reductions from this source sector. This program applies to all plants having a capacity over 30 MW, annual generation over 50 GWh and a capacity factor of 5% or more. The program has set best practice efficiencies (sent out) for new/refurbished power plants as follows: black coal, 42% HHV; brown coal, 31% HHV and natural gas combined cycle, 52% HHV. For existing plants, the businesses sign a 5-year deed of agreement to either improve within the range of best practice performance, or improve the plant to raise efficiency toward the best practice level. Details of the program and guidelines for measurement and improvement of boiler efficiency are given in AGO (2000b, 2001).

5.3.3 Options for Individual APEC Economies or Individual Existing or Future Facilities

Sections 5.3.1 and 5.3.2 presented a discussion of the CO_2 emission reduction that could potentially be achieved by broad application of the identified emission reduction scenarios in the whole APEC region and in the highest emitting APEC economies. These results help to focus on the options that in the longer term can result in relatively large emission reductions in the APEC region as a result of the application of the emission reduction scenarios to a significant share of the existing generating capacity. This section examines the scenarios on an individual basis and provides information that will likely be helpful to APEC economies or facility owners to identify the most promising options for reducing CO_2 emissions in typical situations. CO_2 emission reductions are presented for the scenarios on a percentage and g CO_2/kWh basis.

Finding the optimal CO_2 emission reduction strategy for an individual, or group of electricity generation facilities requires consideration of site specific factors beyond the scope of this study. However, the primary factors that need to be considered for existing facilities are type of fuel burned, net plant efficiency (relative to the best that can be achieved for the fuel and technology), availability and cost of lower carbon fuels, feasibility of fuel switching and environmental co-benefits that a CO_2 reduction option could achieve. In this case, the unavailability or high cost of a low-carbon fuels or of advanced power plant technology may limit the options that are viable, shortening the list of options that can practically be considered.

For new power plants, the fuel and technology to achieve a target CO_2 emission level in gCO_2/kWh can be determined readily from the net plant efficiency and CO_2 emission factors for each of the fossil fuels. Figure 4-1 in Chapter 4 illustrates the overall gCO_2/kWh as a function of net plant efficiency for natural gas, oil and coal. Natural gas yields the lowest CO_2 emission factor, followed next by oil then coal, according to carbon content per unit of heating value. For each of these fuels, the technology yielding the highest technically and economically feasible net plant efficiency should then be chosen. Table 3-6 (Chapter 3) indicates the typical average annual net plant efficiencies achievable with the commercial and near-commercial technologies for fossil fuels. CHP technology is a preferred option for all fuels, as it provides the highest overall energy efficiency. Where cogeneration is not viable, the technologies offering the next highest efficiencies are advanced combined cycles for gas/oil or coal, preferably using supercritical (or ultra-supercritical) steam pressures.

Table 5-10 summarizes data for CO_2 emissions, electricity generation cost and the cost of CO_2 reduction relative to current (year 2000) coal-fired electricity generation technology taken from a recent IPCC (2001a) report on mitigation measures for climate change. Analysis results are available for the United States, an average of Annex I countries and an average of non-Annex I countries. The CO_2 emission factors are consistent with the estimates in this report as a function of fuel type and net plant efficiency. CO_2 capture technology is estimated to reduce CO_2 emissions from coal-fired or gas-fired power plants by about 85%. For the United States, application of CO_2 capture technology is estimated to increase the average electricity generation cost of a modern pulverized-coal fired power plant by 86%, and to increase the electricity generating cost of a gas-fired GTCC power plant by 50%.

Table 5-10 Comparison of Emission Factors and Generating Costs for Technologies to 2010 Relative to Baseline Technologies

Technology	Fuel	Emissions			Generating Cost			Cost of CO_2 Reduction		
		gCO_2/kWh			US cents/kWh			US$/t$CO_2$		
		Annex I	U.S.	non-Annex I	Annex I	U.S.	non-Annex I	Annex I	U.S.	non-Annex I
PC,FGD, NO_x control	Coal	840	906-924	953	4.90	3.3-3.7	4.45	Baseline	Baseline	Baseline
IGCC & supercritical boiler	Coal	697-726	697-770	697-726	3.6-6.0	3.2-3.9	3.6-6.0	-2.70-10.90	-21.8 to 45.80	-2.70-54.50
GTCC	Natural gas	378-447	374-473	378-447	4.9-6.9	2.9-3.4	4.45-6.9	0-42.50	-14.40 to 2.20	0-4.60
PC,FGD,CO_2 capture	Coal	147	147	147	7.9	6.3-6.7	7.45	43.40	38.40 to 39.50	37.00
GTCC+CO_2 capture	Natural gas	62	62	62	6.4-8.4	4.4-4.9	5.95-8.4	19.40-45.00	8.20 to 19.10	16.90-44.50

Source: IPCC, 2001a
Annex and non-Annex I results based on average of data in OECD database; U.S. results based on data from U.S. EIA. Cost estimated in 1998.

The CO_2 emission reduction that could be achieved at an individual power plant was determined for each of the previously described scenarios. In this case, the scenario was considered to be 100% applicable to a target plant assumed to be performing at the average emission rate and efficiency determined for the APEC region (Table 5-5). This analysis used the same assumptions for the fuel type, net plant efficiency and CO_2 emission rate of the target existing plant, and for the fuel/technology changes or improvements from each scenario that have been described previously in Tables 5-1 through 5-8 (see Appendix E for summary of data for all scenarios).

Figure 5-2 summarizes the impacts of application of each scenario to the target power plants, showing the reduction in CO_2 emissions in terms of both the percent of the plant's initial emissions and the gCO_2/kWh. The results are shown in ranked order by gCO_2 reduced per kWh of electricity generated, from most to least effective. It is best to evaluate the options on this basis rather than as percent reduction, as it indicates the true emission reduction normalised to a constant output basis. Examples of this are Scenarios E12 and E18, which show relatively high percentage reductions in CO_2 emissions by repowering with GTCC and CHP, respectively, however, the reductions in gCO_2/kWh are lower than Scenarios which apply to plants having much higher initial CO_2 emission factors.

The scenarios for coal and oil/gas yielding the five highest estimated reductions in gCO_2/kWh are as follows:

- Coal-fired power plants:
  - E16: repower subcritical pulverized coal, stoker or cyclone boiler to an AFBC (or other) biomass energy system;
  - E10: switch subcritical pulverized coal boiler to gas firing;
  - E19: repower subcritical pulverized coal boiler with a combined heat and power system;

– E17: repower subcritical pulverized coal, stoker or cyclone boiler with IGCC or PFBCC; and

– E11: switch subcritical pulvervized coal boiler to oil.

- Oil/gas fired power plants:

  – E13: repower simple cycle gas turbine to a combined cycle;

  – E12: repower subcritical boiler/steam turbine plant with GTCC;

  – E18: repower subcritical boiler/steam turbine plant with combined heat and power system;

  – E3: apply combustion, steam cycle and O&M improvements to gain 5% points for simple cycle gas turbine plant; and

  – E9: switch oil-fired subcritical boiler to gas-fired;

Scenarios E1, E2, E4 and E5, which are based on implementing combustion, steam cycle and O&M improvements, yield estimated reductions less than 120 gCO_2/kWh (percent reductions of 4-10%) on an individual basis. Although these are small compared to the other scenarios analyzed, where applicable, they should be given high-priority consideration, as they can be implemented at comparatively low cost and will enable a plant to improve its economic performance and perhaps its annual electricity generation. For example, application of Scenario E4 throughout the APEC region resulted in the largest estimated total reduction in CO_2 emissions, as discussed in Section 5.3.1 and shown previously in Figure 5-1.

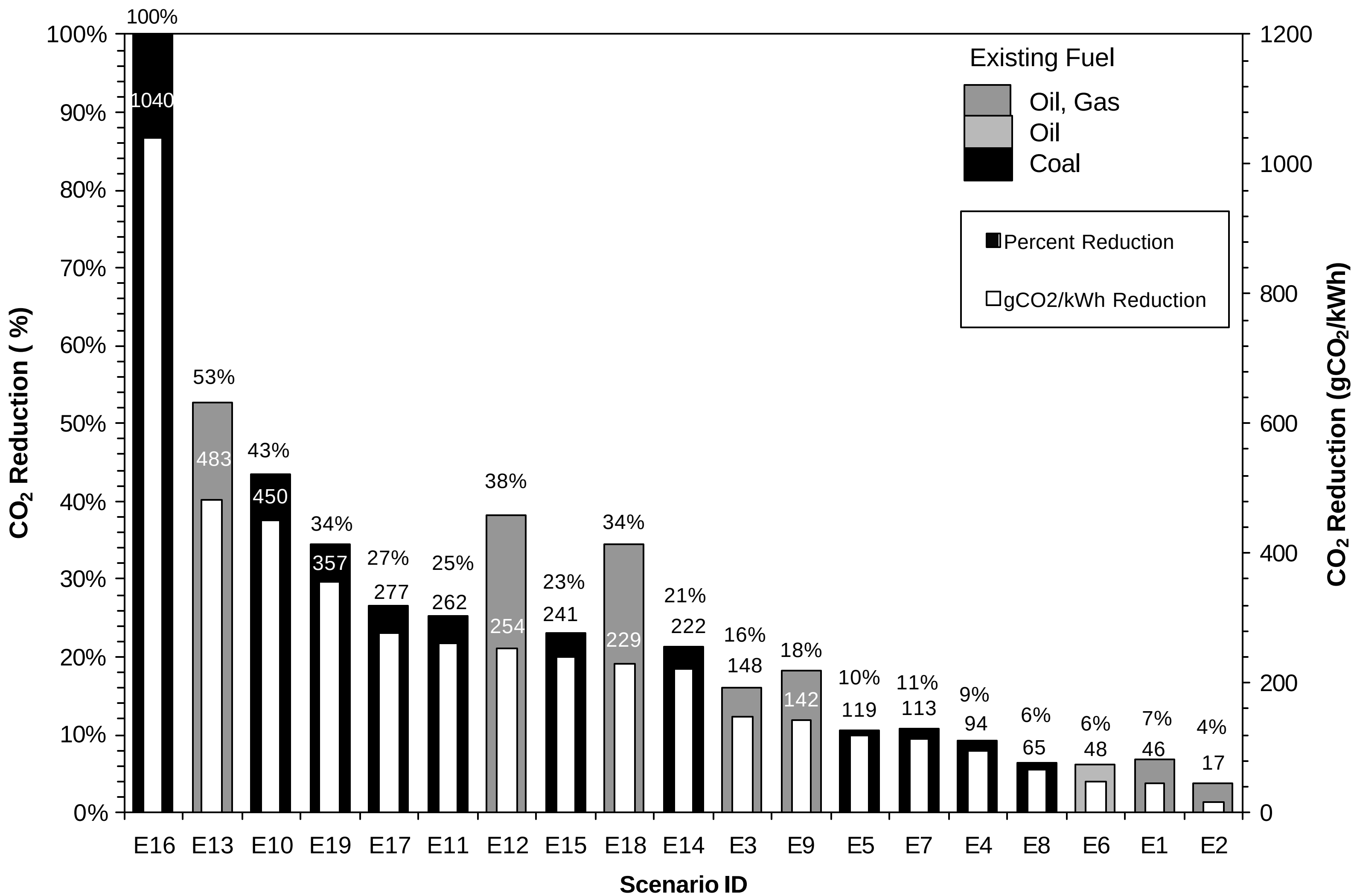


Figure 5-2 **Potential Emission Reduction for Each Scenario in Percent and gCO_2/kWh**

6. Potential Human Health Issues Associated with Emissions from the Electricity Generation Sector

6.1 Emissions Fuel Combustion and Their Potential Effects

6.1.1 Pollution Associated with Electricity Generation

Fuel combustion produces a range gaseous and particulate emissions, and the emission rate and mix of pollutants present in stack gases from a power plant will depend on the type of fuel, energy technology and post-combustion air pollution control systems used. Either directly, or as precursors to the formation of other gases and particles in the atmosphere, these emissions can result in adverse impacts to human health and the environment. Emissions from the combustion of fuels are typically grouped as follows:

- Greenhouse gases: carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O);
- Common air contaminants: carbon monoxide (CO), nitrogen oxides (NO and NO_2 expressed as NO_2), sulphur oxides (SO_2 and other oxidized forms of sulphur expressed as SO_2), volatile organic compounds (VOC, excluding methane), and particulate matter (total, PM_{10} and $PM_{2.5}$); and
- Toxic or hazardous air contaminants: lead, cadmium, arsenic, hexavalent chromium, nickel, fluorides, mercury.

Older coal-burning power plants are a source of a host of pollutants that can threaten public health and the environment (U.S. PIRG, 1998). Key pollutants of concern from fossil-fuel-fired electricity generation are sulfur dioxide (SO_2) and nitrogen oxides (NO_X), which contribute to the formation of acid rain and are precursors to the formation of secondary particulate in the atmosphere. Acid rain can lead to acidification of surface waters and significant adverse impacts to aquatic habitat and fish. At elevated ambient temperatures and with poor atmospheric ventilation, NO_x and VOC emissions can participate in complex photochemical reactions in the atmosphere to increase ground-level ozone concentrations. Several hazardous air pollutants including mercury from coal-fired power generation can be of concern for human and ecosystem health (Burtraw, et al., 2000).

Table 6-1 summarizes general information on the types and significance of pollutants emitted from burning fossil fuels for electricity generation. Natural gas combustion emits very low levels of sulfur dioxide and lower NO_X and fine particulate emissions, and results in less formation of secondary pollutants from precursor emissions than coal (Russell, 1997). Compared to coal and oil, natural gas emits low emission levels of any potentially hazardous air pollutants. Oil has a higher sulphur content than natural gas and, thus oil combustion leads to higher SO_2 emissions for the same energy output. Emissions of NO_x and particulate matter from oil combustion also tends to be higher than from natural gas for the same output energy.

Table 6-1 Summary of Typical Pollutants from Fossil-fired Power Plants

	Fuel		
Pollutant	Coal	Oil	Gas
SO_2	Dependent on sulphur content of coal. In the U.S., accounts for 2/3 of all SO_2 emissions	Emitted in low amounts, dependent on sulphur content of fuel	Very low for merchantable natural gas.
NO_x	In U.S., electricity generation represents 30% of NO_x emissions. Created from fuel NO_x and thermal NO_x.	Similar to coal, newer plants have better emission controls. Created from fuel NO_x and thermal NO_x.	Lower emissions than coal by up to a factor of 10.
Ozone	Formed in air from photochemical reactions involving NO_x and VOC's	Formed in air from photochemical reactions involving NO_x and VOC's	Formed in air from photochemical reactions involving NO_x and VOC's
Particulate Matter	From particulate passing through emission control equipment and from secondary reactions of NO_x, SO_2 and ammonia in the atmosphere.	From combustion and secondary reactions of NO_x, SO_2 and ammonia in the atmosphere.	From secondary reactions of NO_x, SO_2 and ammonia in the atmosphere.
Heavy Metals	Mercury Arsenic Beryllium Cadmium Chromium Lead Manganese Nickel	Very low amounts, except nickel and some other heavy metals depending on source of crude oil.	Essentially none

6.1.2 Typical Health Effects of Common Pollutants

6.1.2.1 Carbon Dioxide

Carbon dioxide is a colourless, odourless gas that is the most significant greenhouse gas emitted from fossil-fuel-fired electricity generating facilities. Carbon dioxide is naturally present in the atmosphere and is not commonly considered to be an air pollutant. Concern about carbon dioxide stems from its projected contribution to global warming and the adverse effect climate change will likely have on human health and the environment.

Global warming may affect the following health-related areas: temperature-related illness and death (both from heat and from cold), natural disasters and extreme weather events, air pollution, water-borne and food-borne disease, and diseases carried by rodents and vectors (such as mosquitoes and ticks) (WHO, 2001). In addition to the spread of infectious diseases such as malaria, dengue fever, and schistosomiasis (Bachrach, 2001), global warming can aggravate air quality problems, which will increase the health effects of the other air pollutants described below.

6.1.2.2 Nitrogen Dioxide

Nitrogen dioxide is a brownish gas that causes irritation of mucous membranes in the respiratory tract and increased risk of respiratory irritation and infection, particularly for children and asthmatics. Recurrent exposure to high concentrations of NO_2 can lead to reduced lung function and long-time exposure to the pollutant can cause irreversible lung damage. Also, NO_2 is an important precursor to ground-level ozone formation through photochemical reactions involving volatile organic compounds (VOC). NO_2 causes a brown colour in the atmosphere at elevated concentrations and reacts in the atmosphere with ammonia to form fine particulate salts, which reduce visibility and increase $PM_{2.5}$ concentrations.

6.1.2.3 Sulphur Dioxide

Sulphur dioxide is a colourless gas with a strong odour. It is absorbed by the mucous membranes in the respiratory system, leading to irritation, coughing, chest discomfort, reduced lung function, respiratory diseases and increased risk of morbidity and mortality. SO_2 has been investigated extensively in epidemiological studies and is thought to worsen the effects of inhalation of particulate matter and to correlate with chronic bronchitis. It reacts with ammonia in the atmosphere to form fine particulate salts, which reduce visibility and increase $PM_{2.5}$ concentrations.

In addition to the human health effects of sulphur dioxide, it is the main contributor (NO_x has less effect) to the formation of acid rain, which can result in adverse effects to aquatic habitat, surface water, land, forests, buildings and other structures. The acidification of lakes and streams can lead to an increase in leaching of aluminium from soil into surface water and a decrease in water pH. A decrease in water pH can result in chronic stress that may not kill individual fish, but leads to lower body weight and smaller size, making fish less able to compete for food and habitat (U.S. EPA, 2001).

6.1.2.4 Particulate Matter

Particulate matter includes mineral, carbonaceous and other types of particles, as well as a mix of chemical compounds that may be adsorbed or adhered to the particle, depending on its origin. Particulate matter may be a primary pollutant such as smoke, emitted directly into the atmosphere, or a secondary pollutant formed by chemical reactions of gaseous pollutants in the air.

At elevated levels, particulate matter can cause respiratory irritation, coughing, increased risk of respiratory illnesses such as pneumonia, asthma and bronchitis, reduced lung function, reduced pulmonary function and increased mortality. Particles over 10 microns are deposited in the upper respiratory tract and are of less concern than PM_{10} (less than 10 microns) and $PM_{2.5}$ (less than 2.5 microns). $PM_{2.5}$ is considered to be the particulate size range of primary concern for health impacts. $PM_{2.5}$ particulate matter poses the greatest risk to human health because it can pass through the respiratory system deep within the lung leading to increased morbidity and mortality (Karunaratne and Wijetilleke, 1995).

Recent studies on the effects of chronic exposure to air pollution have singled out particulate matter as the pollutant most responsible for reducing life expectancy, although other pollutants may also play an important role. (WRI, 1998). Particles less than 10 µm are also responsible for reducing visibility (NSW EPA, 2001). PM_{10} has been declared toxic in Canada under the Canadian Environmental Protection Act and targets with timetables for reduction of emissions have to be submitted by key industrial sectors.

6.1.2.5 *Volatile Organic Compounds*

As defined by the U.S. EPA, volatile organic compounds are gaseous organic compounds, excluding those with negligible photochemical reactivity, such as methane, ethane and other compounds. VOCs are reactive in the atmosphere and can lead to increased formation of ground-level ozone through complex reactions with NO_x in the presence of sunlight. VOCs arise in combustion processes from incomplete combustion of the fuel.

6.1.2.6 *Ozone (ground-level)*

Ozone is a colourless, reactive oxidant gas that is formed at ground-level from photochemical reactions involving principally NO_x, VOC and, to a lesser degree, CO. Ozone is one of the main concerns in urban smog because of the adverse effects on human health that can arise from both short-term and long-term exposure to elevated concentrations. Ozone causes respiratory and eye irritation in humans and can damage vegetation and building materials.

Short-term effects include eye, nose and throat irritation, chest discomfort, increased risk of respiratory illnesses and asthma attacks, as well as decreased pulmonary function. Ozone increases inflammation and diminishes immune function to the lungs, making the young and older adults more susceptible (Davis, et al., 2000) to its adverse effects.

Ozone is not emitted from fuel combustion processes, but may form near ground level as a result of photochemical reactions involving ozone precursors emitted from combustion, evaporative, process and natural emission sources as they disperse in an airshed under certain climatic and meteorological conditions. The potential for photochemical formation of ground-level ozone becomes increasingly more significant as ambient temperatures rise above about 27°C and when there is poor atmospheric ventilation. Ground-level ozone is a fairly common problem in major urban areas of the world, often as a result of high levels of emissions from transportation and major industry sources. Ozone can also be formed during long-range transport of pollutants, which can lead to health and environmental impacts substantial distances away from the source of emissions. The chemical processes leading to ground-level ozone formation can also lead to formation of secondary fine particulate matter that becomes visually evident as haze.

6.1.2.7 *Hazardous or Toxic Pollutants*

Mercury is a toxic, heavy metal that is a trace constituent of coal, and is released to the atmosphere in very low concentrations when coal is burned. The mercury emission rate associated with coal combustion depends on the coal's mercury content and the amount of coal being burned. Mercury is more of a concern than many other trace contaminants as it can circulate in the air for extended periods on the order of a year, and can be transported thousands of miles from its source. Eventually mercury in the air is deposited on land and in water where it moves up the food chain into fish, and eventually humans and animals that eat fish. Especially susceptible are young children and foetuses. Mercury affects the major systems of the body including the brain, central nervous system, digestive system, and the immune system (Bachrach, 2001, U.S. EPA, 2000b). At unsafe levels, mercury also can affect the liver, kidneys, and pancreas and can cause blurred vision, as well as a loss of hearing and motor skills.

The U.S. EPA estimates that coal-fired power plants emitted 39 tonnes of mercury in 1999 from 1149 units at 464 plants in the United States (U.S. Fed. Reg., 2000). This estimate was based on significantly better information than was available for previous emission estimates, and was determined from data for the mercury content of coal burned at each coal-fired utility over a year and the efficiency of existing emission control devices for removal of divalent, elemental and particulate forms of mercury. Coal-fired utility boilers contribute approximately 33% of the mercury emissions in the U.S. and are the largest anthropongenic emission source, followed next by emissions from municipal waste incinerators, medical waste incinerators and hazardous waste incinerators. On December 14, 2000, the U.S. EPA announced it will regulate emissions of mercury and other air toxics from coal-fired and oil-fired electric utility power plants (U.S. EPA, 2000a). Under this decision, the U.S. EPA plans to propose a regulation for control of mercury and other air toxics from coal and oil fired power plants by the end of 2003 (U.S. EPA, 2000b). It is anticipated that the electric utilities would have until December, 2007 to come into compliance with the new regulation (U.S. DOE, 2001b).

The U.S. Department of Energy mercury control program has been actively supporting the development of improved mercury emission control equipment since the early 1990's. Extensive data on mercury in coal and discharges of mercury to air and water from coal-fired power plants and coal preparation plants was developed in 1993-96 through testing programs. The data showed that about 37% of the mercury in coal is removed by coal cleaning processes and that about 50% of the mercury in coal combusted in plants is captured by pollution control installed to control other pollutants. The level of mercury capture varies widely from nominal levels of 0-30% for electrostatic precipitators, to about 55% for wet scrubbers, and up to 90% for dry flue gas desulfurization scrubbers when coupled with baghouses.

As described by the U.S. DOE (2001b), focused support of improved mercury control technologies in the United States started in 1995 with two years of laboratory-scale investigations into controlling mercury and fine particulate from coal-fired boilers. Subsequent projects involved larger-scale studies and tests of five promising technologies. In August, 2000, the U.S. DOE awarded cost-shared contracts to the following two companies for full-scale tests:

- McDermott Technologies Inc., in conjunction with Babcock and Wilcox, to demonstrate mercury control technology applicable to coal-fired power plants equipped with wet scrubbers. The technology is planned to be tested at full-scale at the Michigan South Central Power Agency's 55 MW Endicott Station in Litchfield, Michigan, and the Cinergy Corporation's 1300 MW Zimmer Station near Cincinnati. The technology is hoped to attain 90% removal of mercury at one-half to one-fourth the cost of today's activated carbon mercury control technology.

- ADA Environmental Solutions to develop a dry sorbent technology and demonstrate its performance at four different utility power plants equipped with either electrostatic precipitators or baghouses. PG&E Generating is planned to provide two test sites that fire bituminous coals. Wisconsin Electric Power Company is providing a third site that burns Power River Basin coal and uses electrostatic precipitators for particulate control. A fourth plant with fabric filters for particulate control will be added to the test program.

The U.S. DOE selected six other projects in May, 2001 that involve research and development of novel mercury control systems.

Although other potentially hazardous substances can be emitted from fossil fuel fired electricity generation, they are usually at low concentrations and the potential for causing significant adverse human health effects can be mitigated by use of modern pollution control systems and by following best engineering design practices. However, the potential for health impacts from emissions from a power plant should be assessed on a site specific basis, considering pollutant emission levels, the surrounding land use, meteorological conditions that are representative of the area and any influence of local terrain on concentration levels. Emissions of the following toxic or hazardous substances from large utility electricity generating plants in Canada were considered to not pose an identifiable public health problem from their potential cancer and noncancer effects during a major study of toxic emissions from coal fired power plants in Canada completed for a 1997 Issue Table by Environment Canada and industry representatives (Shaw, 1997).

- Arsenic
- Benzene
- Cadmium
- Chromium (VI)
- Dichlormethane
- Lead
- Nickel
- Polycyclic aromatic hydrocarbons
- Benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene
- Ideno(1,2,3-cd)pyrene
- Trichloroethylene

The potential health issues associated with emissions of the toxic pollutants listed will depend on the situation in each APEC economy. Local environmental and health agencies should be consulted regarding ambient air quality standards and risk assessment procedures if these or other contaminants are a concern.

6.1.2.8 Carbon Monoxide

Carbon monoxide is a clear, odourless gas that reduces the blood's capacity to carry oxygen to tissues in the body. At low levels CO impairs perception and judgement, with effects worsening to include drowsiness or headaches and general discomfort, leading ultimately to convulsions and coma at high concentrations. Elevated levels of carboxyhemoglobin (CO bound to the hemoglobin in the blood) are particularly dangerous for people with heart disease or respiratory problems, pregnant women, and infants (Karunaratne and Wijetilleke, 1995). CO also participates to a minor extent in photochemical smog reactions that lead to increased ground-level ozone formation.

Proper design and operation of combustion equipment and discharge stacks at a power plant should keep CO emission levels and, hence, ambient concentrations at low levels. Combustion control instrumentation and emission monitoring systems should be used to ensure complete combustion is being achieved in combustion systems and that CO levels in stack gases are low.

6.2 AIR QUALITY ISSUE IN THE APEC REGION

6.2.1 WHO Air Quality Guidelines

Health research and cost benefit studies continue to support setting stricter ambient air quality and emission standards to prevent adverse health effects from pollutants. Table 6-2 below outlines the 1999 World Health Organisation Guidelines for pollutants produced from electricity generation technologies. These guidelines are a basis for judging the cleanliness of the air in APEC cities for which data were found in the published literature and the significance of power generation processes to contribute pollutants of potential concern.

Table 6-2 World Health Organization Guidelines for Air Pollutants

Compound	Annual ambient air concentration ($\mu g/m^3$)	Health endpoint	Observed effect level ($\mu g/m^3$)	Uncertainty factor	Guideline Value ($\mu g/m^3$)	Averaging period
Carbon monoxide	500-7000	Critical level of COHb < 2.5%	n.a	n.a.	100 000	15 minutes
					60 000	30 minutes
					30 000	1 hour
					10 000	8 hours
Nitrogen dioxide	10-150	Slight changes in lung function in asthmatics	365-565	0.5	200	1 hour
					40	1 year
Ozone	10-100	Respiratory function responses	n.a.	n.a.	120	8 hours
Sulphur dioxide	5-400	Changes in lung function in asthmatics	1000	2	500	10 minutes
		Exacerbation of respiratory symptoms in sensitive individuals	250	2	125	24 hours
			100	2	50	1 year
Mercury, inorganic	$(2\text{-}10) \times 10^{-3}$	Renal tubular effects in humans	0.020 (LOAEL)	20	1 (GV)	1 year

Source: WHO, 1999

When considering the relationship between air quality and health effects, it is important to recognise the local, regional, and cultural variation in factors that effect exposure to air pollutants. In addition to variation in the emission sources between countries and regions, the temperature, altitude, and indoor exposure to pollutants all effect the personal health of the population.

The various health implications of air quality can be magnified or reduced depending on the amount of time spent indoors and the indoor air quality. Globally, about half of the world's homes use combustion of some fuel to provide energy for cooking and/or heating. In China, for example, it has been estimated that coal burning results in particle concentrations up to 5,000 mg/m^3 in indoor living areas. (WHO, 1999). Countries burning brown coal (or lignite) for domestic heating are likely to experience high concentrations of smoke and SO_2. The total human exposure to many important air pollutants can be much higher in the homes of the poor in developing countries than in the outdoor air of cities in the developed world due to the high pollutant concentrations and populations involved.

Increased inhalation volumes resulting from the decreased partial pressure of oxygen at higher altitude can lead to increased intake of airborne particles and perhaps changes in patterns of deposition. The greatest effect is expected for recently relocated portions of the population that are not accustomed to the effects of altitude. Additionally, extreme temperatures also lead to increased exposure to pollutants. Warmer temperature days not only encourage more time spent out of doors, but also increase the volume of air inhaled and may favour exposure to outdoor pollution over indoor pollution from open windows and doors. Humidity may change the patterns of deposition of smaller particles to larger airways in the lung due to increased hygroscopic growth.

Often, individuals with a poorer standard of living have increased susceptibility to the effects of air pollution. Nutritional deficiencies, overcrowding, poor sanitation, increased infectious diseases, and a low standard of medical care can lead to the delayed clearance of particles from airways leading to increased cases of respiratory problems among this sub-population.

6.2.2 Typical Air Quality in APEC Cities

Concentrations of emitted pollutants and population exposures to air pollution vary substantially from country to country within the APEC region, though densely populated urban regions especially in developing countries tend to have the worst air quality. As there are relatively few locations where all of the classical air pollutants have been measured simultaneously, or over extended periods (WHO, 1999), it is only possible to point out significant air quality values rather than a comprehensive pollution map or annual trends.

Although somewhat dated, Figure 6-1 summarizes 1995 annual average concentrations of NO_2, SO_2, and total particulate matter for 49 cities in 15 of the APEC economies. NO_2 and SO_2 are largely produced by combustion of fuels, while TSP is emitted from a wide variety of combustion, non-combustion and natural sources. In many Chinese cities, annual concentrations of TSP, NO_x and SO_2 in 1995 were very high compared to WHO guidelines and levels in other APEC economies. SO_2 levels reported from "residential" locations in China often exceed those from "commercial" regions of the city and are comparable with the levels in industrial zones due to the impact of the combustion of sulphur in coal. Annual TSP concentrations in 1995 were also well above WHO guidelines in Jakarta, Mexico city, Manila and Bangkok. Annual NO_2 concentrations are a problem in many cities in the APEC region, mostly in the developing economies, but also in large cities in North America. Emissions from electricity generation undoubtedly make a contribution to the observed ambient pollutant concentrations in the cities listed in Figure 6-1, though data is not readily available to indicate if the share of emissions made by electricity generation in these areas is significant or how it varies across the APEC economies.

Some of the most polluted megacities in the world are within the Asia-Pacific region including: Beijing, Jakarta, Los Angeles, Mexico city, and Moscow. The World Health Organisation estimates that 12 of the 15 cities with the highest levels of particulate matter and 6 of the 15 with the highest levels of sulphur dioxide are in Asia. As shown in Table 6-3 for 1997, the ambient concentration of total suspended particulate matter and sulphur dioxide exceed WHO standards in the APEC region. Premature mortality and respiratory disease caused by poor air quality have been documented in 16 large metropolitan centres in the region. Although air quality is improving in some Asian countries, such as South Korea, maximum pollutant concentrations are still significantly above the WHO standards in APEC economies.

Among different environmental pollution problems, air pollution is reported to cause the greatest damage to health and loss of welfare from environmental causes in Asian countries. Additionally, in developing countries outside of Asia, the air quality in large cities is remarkably poor. Over one million out of 18 million residents in Mexico city suffer permanent breathing difficulties, headaches, coughs and eye irritations.

Table 6-3 Ambient Concentrations of Pollutants in Asian Cities in 1997

Country	City	Suspended Particulate Matter annual mean ($\mu g/m^3$)	Sulphur Dioxide annual mean ($\mu g/m^3$)
China	Beijing	(*) 370	(*) 115
India	Calcutta	(*) 393	54
Indonesia	Jakarta	(*) 271	n.a.
Japan	Tokyo	50	20
Malaysia	Kuala Lumpur	(*) 119	24
Philippines	Manila	(*) 90	34
Thailand	Bangkok	(*) 105	14

Note: (*) exceeds WHO guidelines; n.a. = not available.
Source: AIT, 2000

The available data presented in Figure 6-1 provides data on an annual average basis, which provides a good indication of air quality, however, data for 1-hour and 24-hour averaging periods needs also to be considered when assessing the potential for human health effects of air pollutants. For most cities having annual monitoring data, a decline in mean annual SO_2 concentration has been observed through the 1990s, which suggests ambient SO_2 concentrations in some of the cities may have decreased from what is indicated in Figure 6-1 (WHO, 1999). Differences in annual average concentrations across the range of cities surveyed are most evident for particulate matter and SO_2. The most dramatic reduction of air pollution with SO_2 was reported for Mexico City, where the concentration in various residential areas dropped from 100-140 $\mu g/m^3$ in 1990-1991 to 32-37 $\mu g/m^3$ in 1995-1996. In the most polluted Chinese cities, the annual mean declined between 1% and 10%.

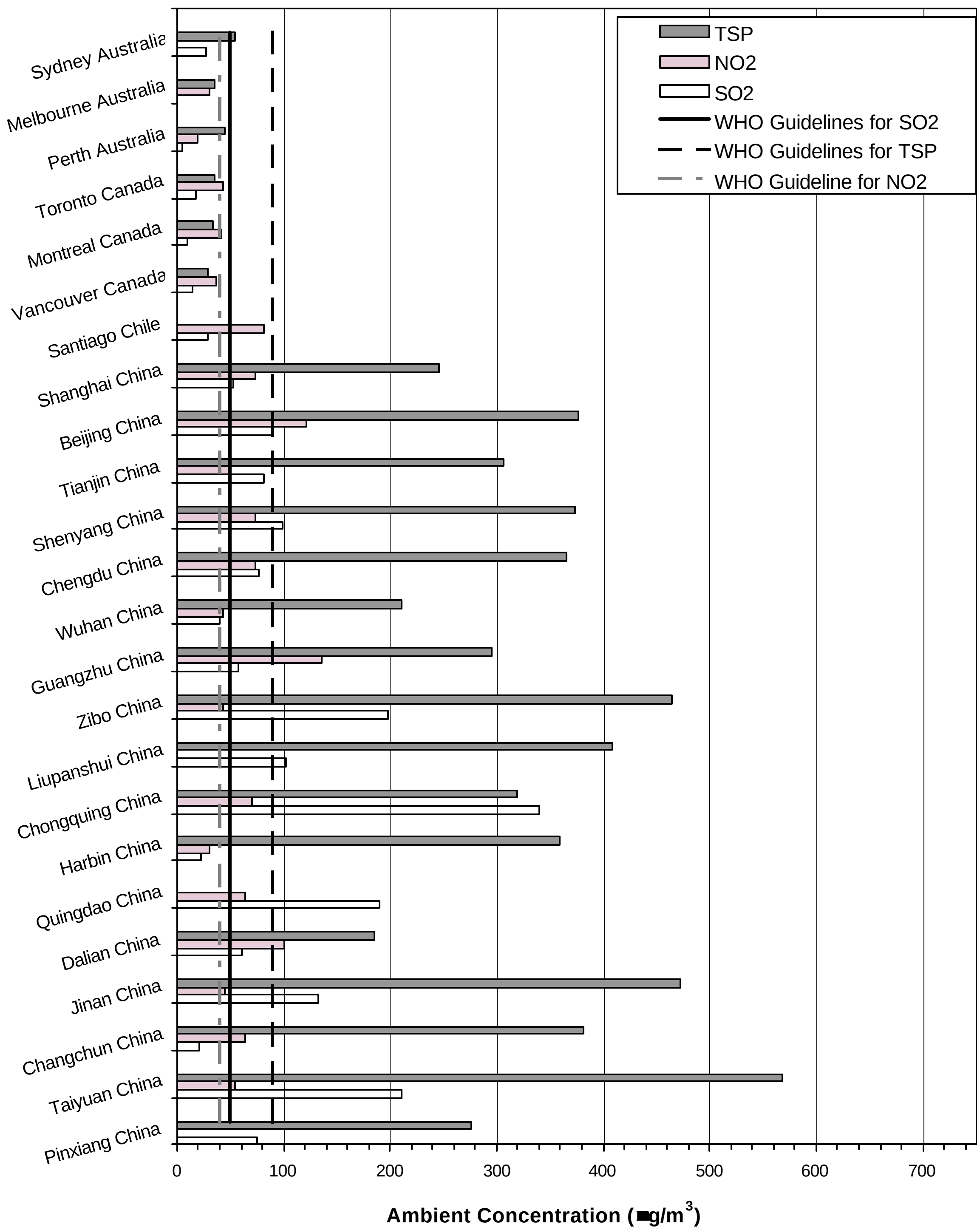


Figure 6-1 Annual Mean Concentrations of Major Pollutants in 49 APEC Cities for 1995

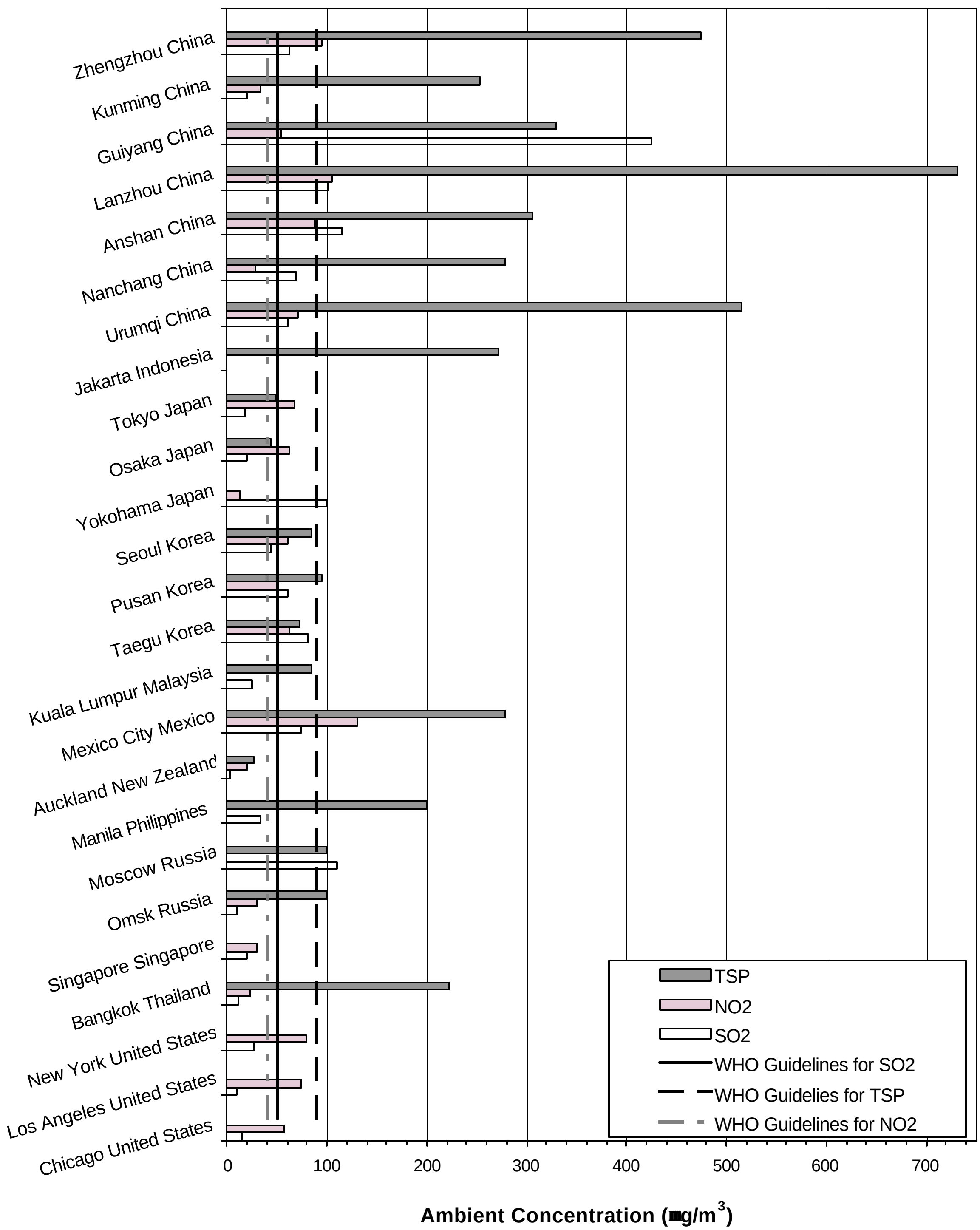


Figure 6-1 Annual Mean Concentrations of Major Pollutants in 49 APEC Cities for 1995 (Continued)

6.2.2.1 Suspended particulate matter

Exposure to particulate matter may be the largest problem as far as direct effects on human health in Central Asian cities (Bakkes, et al., 2000). The Asian Development Bank found that 10 of 11 cities in Asia exceed WHO guidelines for particulate matter by a factor of at least three. (AIT, 2000). In contrast, the APEC region also contains two of the three megacities (Tokyo, New York, and London) in the world in which the particulate concentration is within the limits prescribed by the World Health Organisation

Unlike SO_2, there is no evidence of a trend in average TSP concentration through the 1990s. The ambient monitoring data from the 1990s shows increasing as well as decreasing concentrations in a similar number of cities (WHO, 1999). Although data from Bangkok and Mexico City show decreases in the concentration of TSP over the last decade, the decrease is either unsteady or small. However, in some Chinese cities the change in TSP is more apparent and increases rather than decreases (TSP concentration in Guangzhou has increased from less than 150 µg/m^3 in 1990-1992 to more than 300 µg/m^3 in more recent years). In recent years, major steps have been taken to reduce emissions and improve the air quality in Beijing and other major cities in China, suggesting that trends observed in prior years may not give a reliable indication of current conditions.

6.2.2.2 Nitrogen dioxide

As seen in Figure 6-1, 30 of the 49 cities listed have NO_2 values above the WHO guideline, interestingly enough, unlike TSP, the cities with high NO_2 ambient concentrations are not confined to Asia, as several North American cities have levels higher than 40 µg/m^3. The trends in NO_2 pollution vary between the cities, but a 5-10% annual increase in concentration is more common than a decrease. This is consistent with the volume of vehicle traffic in each city as increasing pollution trends are observed in the cities with high and increasing traffic levels.

In Southern Asia or in Latin America, this high NO_2 concentration combined with the intense UV radiation results in photochemical smog with high oxidant concentrations (WHO, 1999). For example, in Mexico city, the ozone concentration exceeds the WHO guideline of 120 µg/m^3 over 300 days per year. There has, however been a decrease in the annual mean O_3 concentration, indicating slow improvement of air quality during non-extreme days.

6.3 APPLICATIONS IN THE APEC REGION

6.3.1 Overall impact of Various Thermal Power Technologies on Air Quality

In general, there is a qualitatively obvious, but not quantitatively explicit relationship between ambient air quality and health effects. There are directional similarities between air quality trends and emission trends for any given pollutant (U.S. EPA, 2001a). Reductions in the quantity of greenhouse gas emissions will tend also to decrease the emissions of common air pollutants associated with combustion processes. Thus, beneficial reductions in emissions of pollutants having adverse health effects, such as SO_2 and particulate matter, can be achieved as a result of some measures to reduce greenhouse gas emissions, resulting in significant co-benefits.

Short-term ambient concentrations of contaminants are partly a function of the emission rate and partly dependent on the local meteorology and the discharge characteristics of the source. Thus, in some cases, there can be non-linear changes in maximum ambient concentrations in the vicinity of a plant as a result of a change in the emission rate from the plant, though they will be in the same direction. Generally speaking, reducing pollutant emission rates will reduce average ambient pollutant concentrations, reduce the formation of secondary pollutants and reduce environmental and human health effects.

Improvements in the efficiency of a power generation facility will decrease the amount of fuel burned to produce a given amount of electricity, and reduce the emission rate for most pollutants. The SO_2 emission rate from a plant will vary fairly linearly with the feedrate of sulphur to the combustion process, so decreasing the fuel consumption rate by increasing plant efficiency will result in a similar reduction in the SO_2 emission rate, and an improvement in air quality. Reducing fuel consumption rate will also yield a roughly proportional reduction in the emission rate of particulate, carbon monoxide, VOC and some fuel-dependent hazardous pollutants. Changes in the NO_x emission rate resulting from plant efficiency improvement will not tend to be in proportion to fuel consumption, but instead be dependent on the type of energy system and the type of NO_x control that is being used.

As with switching power station configurations, fuel switching can also lead to decreased emissions by utilising fuels with lower amounts of pollutant forming substances. Modern gas-fired power stations, for example, tend to be less polluting than power plants using coal or oil. However, advanced coal and oil fired power plants can now be designed and operated with attractively low pollutant emission rates per unit of power produced. The replacement of coal and high sulphur oil by natural gas in Seoul has led to a downward trend in ambient SO_2 concentrations. In terms of total health benefits, greenhouse gas mitigation that leads to lower emissions of fine particulates or reductions in coal combustion, may lead to greater ancillary benefits than those that reduce emissions of course sized particles or that reduce emissions from inherently low particulate emissions sources (such as natural gas fired systems) (Davis, et al., 2000).

Studies have shown significant associations between long-term exposure to air pollution and human mortality (Davis, et al., 2000). Decreases in emissions of pollutants from power generating facilities that result in decreases to the ambient concentrations of pollutants will decrease the incidences of negative health effects. A Chilean analysis of air pollution estimated the effects of a 10% reduction of $PM_{2.5}$ emissions predicted to occur by 2020 (Cifuentes, et al., 2000). The magnitude of these effects are shown in Table 6-4 below and include reductions in premature deaths, respiratory aliments, and doctor visits. On a case specific basis, a 10 $\mu g/m^3$ reduction in average daily levels of PM_{10} was estimated to reduce mortality by 0.5% to 7% (Davis, et al., 2000).

Table 6-4 Predicted Reduction in Health Impacts in Chile from a 10% Decrease in $PM_{2.5}$ Emissions by 2020

Health Outcome	Incident Reduction
Premature Death	2,779
Chronic Bronchitis	14,348
Hospital Admissions	16,663
Child Medical visits	100,713
Emergency Room visits	220,730
Asthma Attacks & Bronchitis	2,635,589
Restricted Activity Days	55,568,210

A health impact analysis has been conducted for a proposed 1000 MW coal-fired power plant planned to be built in the Thapsake District in Southern Thailand in 2006-2007, and for the existing 300 MW Mae Moh lignite-fired power plant in Northern Thailand in which Shrestha and Lefevre (2000) estimated the effects of PM_{10} and SO_2 emissions. The Thapsake plant will burn imported coal and be equipped with an electrostatic precipitator for particulate control and FGD for SO_2 control. Emission rates for this plant are 27.2 g/s for PM_{10} and 76.4 g/s for SO_2. The Mae Moh plant burns high-sulphur lignite (2.6%S) and is equipped with FGD having a control efficiency of about 90%. The emission rates for the Mae Moh plant are 39.4 g/s for PM_{10} and 61.9 g/s for SO_2. The analysis considered five adverse health outcomes and estimated the associated monetary cost for the population exposed to emissions from the plants within 1000 km. The health effects of the plants in these rural areas were found to be significant, as summarized in Table 6-5, and were equivalent to monetary damages of US$1,8 million/year for the Thapsake plant and US$2.6 million/year for the Mae Moh Plant, in 1995 dollars. The monetary impacts of the plants are dominated by the cost associated with the increases in chronic mortality. The higher health impacts of the Mae Moh plant are due to the higher local population density and higher ambient concentrations of SO_2.

Table 6-5 Estimated Health Impacts of the Thapsake and Mae Moe Power Plants

Health Impacts	Units	Thapsake Plant*	Mae Moh Plant*
Acute Mortality (deaths from short-term exposure)	Year of life lost/yr**	1.89	3.3
Chronic Mortality (deaths from long-term exposure)	Year of life lost/yr**	34.7	50.2
Acute Respiratory Symptom	Days/yr	64,600	93,500
Cardiac Hospital Admissions	Cases/yr	1.1	1.6
Respiratory Hospital Admissions	Cases/yr	1.2	1.8
Local population density	per km^2	28	138
Regional population density	per km^2	25	25

* Results predicted using the RUWM model, considered to be the more accurate of the three that were used. RUWM is the Robust Uniform World Model developed by the International Atomic Energy Agency for estimating the health impacts of power generation facilities (IAEA, 1999). RUWM incorporates the effects of stack height and assumes that plume rise is controlled by bouyancy, there is a uniform distribution of wind direction and there is a uniform distribution of local and regional population.

** Cumulative reduction in lifetime expectancy.

Coal-fired power plants are a major source of air pollution in PR China. In 1994, power plants over 6 MW capacity emitted approximately 28% of the national emissions of particulate matter and 32% of the national emissions of sulphur dioxide (Battelle, 1998). Substantial progress has been made in PR China since 1994 to install improved emission control systems on power plants and to shut-down small inefficient and higher polluting power plants. Power plants are required to utilize high-efficiency electrostatic precipitators to control emissions of particlutate matter. Greater use is now made of flue gas desulphurization equipment to reduce SO_2 emissions. Battelle (1998) identified the following options for reducing the impacts from China's power sector on air quality, human health and the environment:

- Increase the use of natural gas and clean renewable energy;
- Increase the efficiency of existing and future coal-fired power plants;
- Improve the quality of as-fired coal (lower ash and sulphur content) by mining higher quality coal or using coal cleaning technology;
- Site power plants to minimize environmental impacts;
- Increase the use of flue gas desulphurization technologies; and
- Implement advanced fossil fuel electricity generating technologies, such as GTCC for natural gas and IGCC and PFBC for coal.

Globally, reductions in air pollution tied with mitigating greenhouse gases are predicted by Davis, et al. (2000) to lead to the possible reductions of 4.4 to 11.9 million excess deaths by 2020. Additional burdens on public health from morbidity associated with these exposure are also expected to diminish.

6.3.2 Qualitative Impact of the CO_2 Reduction Scenarios on Air Quality

Implementation of the CO_2 reduction scenarios discussed in Chapter 5 will also result in changes in the emissions of air pollutants from an electricity generating facility. A reduction in pollutant emissions will lower the pollutant load in the local air shed and, for large plants, possibly yield significant reductions on a regional scale. Reducing pollutant emissions will lower the contribution of the plant to maximum ambient pollutant concentrations and any associated adverse environmental and human health impacts. If the air shed in which the plant is located is over-loaded by the cumulative emissions from numerous emission sources, the reduction in emissions from one major sources will reduce the average concentration of pollutants, though may result in only minor reductions in the maximum observed concentrations. A sustained improvement in average air quality will yield reduced cumulative impacts to the environment and to human health in the air shed.

From an air quality perspective, the main co-benefits of CO_2 emission reduction options for thermal power plants arise from reducing emissions of NO_x, SO_x, particulate matter and hazardous air pollutants. A reduction in emissions of these key pollutants has the following potential benefits:

- NO_x: Helps reduce ambient NO_2 concentrations, episodic formation of ground-level ozone, secondary formation of fine particulate matter and acid rain;
- SO_x Helps reduce ambient SO_2 concentrations, acid rain and secondary formation of fine particulate matter;
- PM_{10} Helps reduce ambient PM_{10} concentrations and haze; and
- Hazardous pollutants: Helps to reduce ambient concentrations of hazardous pollutants and secondary effects from deposition of these pollutants in surface waters and uptake by living organisms.

A qualitative rating guide was developed to illustrate the co-benefits to air quality that could potentially be achieved by implementation of the CO_2 emission reduction scenarios analyzed in this study. The guide is intended as a screening tool and indicates qualitatively the relative reduction in emissions of the key pollutants associated with combustion of fossil fuels. As outlined above, a reduction in emissions will tend to result in a reduction in the impacts from an existing or new power plant on air quality and, hence, yield environmental and human health benefits.

Many of the CO_2 emission reduction scenarios lead to some reduction in pollutant emissions, as shown in Table 6-6. The co-benefits of Scenarios E1 and E2 are shown as neutral because the reduction in emissions is anticipated to be small, in proportion to the change in plant efficiency. Scenarios E3-E5 have a somewhat higher potential for providing co-benefits, though these also will be relatively small compared to the benefits for many of the other emission reduction scenarios. Scenario E10 is attractive because of switching to 100% natural gas, which is the cleanest burning fossil fuel, though availability and cost is an obvious issue. Scenarios E12-E13 for oil/gas and Scenario E17 for coal offer substantial emission co-benefits as a result of the increase in fuel efficiency, combined with improved pollution control that is integral to the current advanced systems. Repowering with CHP is beneficial because of the net reduction in fuel combustion and emissions that is achievable by displacing existing fuel combustion by waste heat recovery. The benefit of CHP is higher for coal firing than oil/gas firing because of the differences in emission characteristics of these fuels.

Of course, improvements in air quality can also be achieved independent of CO_2 reduction by retrofiting proven emission control equipment to existing power generating plants, or by repowering using advanced energy and pollution control systems. The USEA (1999) indicates that modern post-combustion flue gas desulphurization controls to reduce SO_2 emissions can consume about 1% of the electricity produced by a coal-fired plant. The analysis in this study illustrates that many of the options identified for reducing CO_2 emissions from the electricity generation sector will also result in reduced pollutant emissions, and yield reduced impacts to the environment and human health.

Table 6-6 Qualitative Rating of Emission and Air Quality Co-Benefits for CO_2 Emission Reduction Scenarios Analyzed in This Study

Scenario	Scenario Description	Existing Fossil Fuel	Existing Technology	NO_2	SO_2	PM_{10}	Hazardous Pollutants
E1	2.5% efficiency increase from combustion, steam cycle and O&M improvement	Oil,Gas	ST Sub	0	0	0	0
E2	2.0% efficiency increase from combustion, steam cycle and O&M improvement	Oil,Gas	GTCC & CHP	0	0	0	0
E3	5.0% efficiency increase from combustion, steam cycle and O&M improvement	Oil,Gas	SC	+	+	+	+
E4	3.5% efficiency increase from combustion, steam cycle and O&M improvement	Coal	PC Sub, PC Super	0/+	0/+	0/+	0/+
E5	3.5% efficiency increase from combustion, steam cycle and O&M improvement	Coal	Stk/Cyc	0/+	0/+	0/+	0/+
E6	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Oil	ST Sub	0/+	+	0/+	0
E7	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Coal	PC Sub	+	+	+	+
E8	Co-fire Boiler with 25% Oil: apply to all existing plants with oil capability	Coal	PC Sub	+	0/+	+	+
E9	Fuel Switch to 100% Gas: apply to all existing plants with gas capability	Oil	ST Sub	0/+	++	+	0/+
E10	Fuel Switch to 100% Gas: apply to all existing plants with gas capability	Coal	PC Sub	++	++	++	++
E11	Fuel Switch to 100% Oil: apply to all existing plants with oil capability	Coal	PC Sub	+	0/+	+	+
E12	Repower with GTCC	Oil Gas	ST Sub	++	++	+	+
E13	Repower with GTCC	Oil Gas	SC	++	++	+	+
E14	Repower with PC Super	Coal	PC Sub	+	+	+	+
E15	Repower with AFBC and 20% Biomass	Coal	PC Sub, Stk/Cyc	0/+	0/+	0	0/+
E16	Repower with AFBC and 100% Biomass	Coal	PC Sub, Stk/Cyc	+	++	0	++
E17	Repower with IGCC or PFBCC	Coal	PC Sub, Stk/Cyc	++	++	++	++
E18	Repower with CHP	Oil Gas	ST Sub	+	+	0	0
E19	Repower with CHP	Coal	PC Sub	++	++	++	+

Legend: + small reduction in emissions; ++ substantial reduction in emissions
0 neutral or minor effect on emissions
– small increase in emissions; – – substantial increase in emissions
/ indicates range of possible effects depending on the energy technology and fuel quality.

7. OBSTACLES AND DATA GAPS

7.1 CURRENT DATA GAPS

From the analysis completed in this study, it is evident that there are gaps in the data presently available on the electricity generation sector in the APEC region. Some of these data gaps arose because of the limited number of responses to the survey questionnaire from the APEC economies. It would be beneficial to future efforts and studies towards reducing CO_2 emissions from the electricity generation sector in the APEC region if the following additional information could be developed:

- **Data regarding electricity generating capacity (i.e., MW), annual electricity generation (i.e., GWh) and net energy efficiency for key energy technologies firing natural gas, oil and coal fuels in APEC economies.**

  Presently, the APEC Energy Statistics report for 1998 provides data for generating capacity and annual electricity generation for all thermal generation from fossil fuels, and does not report comparable data for individual fossil fuels. This study used the commercially available UDI/McGraw-Hill Energy "World Electric Power Plants Data Base", which provided a good basis for the analysis. To refine and reduce the uncertainty in any future estimates of CO_2 emission reductions for the electricity generating sector, such as conducted in this study, better data are needed on electricity generating capacity, annual generation and net plant efficiency for each energy technology and fossil fuel. To reduce the effort required, collection of this data could be limited to APEC economies interested in participating in the study.

  It would also be very beneficial to include summarized statistics in the APEC Energy Statistics report on the magnitude of generating capacity for each fossil fuel, in addition to the aggregate value now reported for thermal generation.

- **Data regarding the future additional generation in each APEC economy by type of fuel, in a level of detail similar to that indicated in the survey questionnaire developed for this study (Appendix A).**

- **Summary data on the type and effectiveness of options implemented in the electricity sector to improve facility efficiency and reduce CO_2 emissions for each fossil fuel.**

  This information would be beneficial to share amongst the APEC member economies to help identify a variety of the most effective measures to reduce CO_2 emissions from the power sector and, thereby, facilitate further innovation and more rapid implementation in other economies. Tracking of these improvements can be done by various methods to different levels of detail. The survey questionnaire (Appendix A) illustrates one approach, though other approaches can be devised that may be more, or less detailed.

- **Data on current generating capacity and annual generation for combined heat and power facilities, and on the opportunities that likely exist for greater use of CHP facilities at industrial host plants to provide electricity to the grid.**

- **Comparative data on electricity generation cost and the cost effectiveness of CO_2 reduction for the more promising options to reduce CO_2 emissions from the electricity generation sector.**

This study did not address the economic feasibility of CO_2 emission reduction options. This is, of course, a primary consideration for the options that have high capital and operating costs, and would be an appropriate next step in the analysis of CO_2 reduction options in APEC economies. Data on cost impacts of CO_2 reduction options would be beneficial for many of the APEC economies, however, it is suggested that such analysis should initially focus on the smaller number of APEC economies identified in this study that are predicted to contribute the majority of CO_2 emissions from this sector.

- **Data on the impact of the electricity generation sector on air quality in the APEC region.**

  To better assess the co-benefits to air quality and human health of implementing CO_2 emission reduction options, information is needed for each APEC economy on emissions from the electricity generation sector by fuel type, and the average and maximum concentrations of pollutants in the vicinity of power plants located near populated areas. The analysis could focus in more detail on effects in developing economies where power plants may be closer to residential areas because of a limited power distribution infrastructure, and meet less stringent emission standards than in the developed economies.

7.2 OBSTACLES TO IMPLEMENTATION OF CO_2 EMISSION REDUCTION OPTIONS

The CO_2 reduction options identified in Chapter 5 fall into one of four categories: 1) improve an existing plant using proven techniques and equipment to achieve small but significant efficiency improvements; 2) switch to lower carbon fuels; 3) repower an existing plant, or construct a new plant using modern or advanced technology; and 4) repower or construct a new cogeneration facility. The obstacles to implementing this range of options varies substantially in nature and difficulty.

The obstacles to combustion, steam cycle and O&M upgrades in the APEC region should be low in the developed economies and likely somewhat higher in the developing economies in the APEC region. The costs associated with this group of options (E1 through E5) are low to medium relative to the remaining CO_2 emission reduction options considered. The lower cost, as well as likely improvements to the plant's output, reliability and environmental performance, should favour implementation. Obstacles to this group of options, if they exist, may be associated with lack of information, operator training, limitations on the access to the required upgraded equipment or instrumentation, limitations imposed by the age or out-dated design of components of the existing power plant equipment; or management and decision making processes that hamper adoption of plant improvements.

Fuel switching options were evaluated in Scenarios E6 though E11 and involved substituting natural gas or oil for the existing higher carbon fuel. The main obstacles to implementation of these options are expected to be limited, or lack of, availability of the substitute fuel in the site location, uneconomic fuel price, insecurity of fuel supply and incompatibility of the existing equipment for firing of the substitute fuel. The cost impact of fuel switching is medium to high compared to the other alternatives, and depends on the equipment modifications required and the cost of the substitute fuel. Upgrading of training of plant personnel may be needed in developing economies to ensure the most efficient plant operation is achieved with the new fuel and equipment. Construction of natural gas pipeline transmission systems in PR China and the ASEAN region will help expand the number of facilities for which fuel switching could be considered an option.

Scenarios E12 though E19 focused on repower options for CO_2 emission reduction, and can also be used to illustrate the merits of greenfield applications of these technologies. Scenarios

E12 and E13 are based on replacing existing oil/gas steam or simple cycle gas turbine systems with high-efficiency combined cycle technology. Scenario E14 involves replacing existing coal-fired technology with proven high-efficiency pulverized-coal supercritical pressure technology. Scenarios E15 and E16 are based on use of well-proven atmospheric fluid bed technology for co-firing biomass with coal. These proposed technologies are being installed in new facilities in North America and the choice of technology is driven largely by plant cost, fuel cost and environmental considerations to obtain timely regulatory approval. Obstacles to implementing these technologies in developing economies are more extensive, and could include the capital cost for imported technology, fuel availability, fuel cost, availability of financing, limited domestic availability of engineering, materials and O&M capabilities, and social and cultural constraints. In the special case of using biomass for electricity generation, only sites with an adequate supply of biomass near the existing plant would be suitable candidates. In some developing economies the size of the existing power plants may be too small to effectively match the repowering option.

Implementation of advanced IGCC and PFBCC technologies, as considered in Scenario E17 faces technical and economic obstacles within the APEC region and, in particular, the developing economies. Obstacles to significant implementation in developing economies include the high capital cost for imported technology, technology transfer arrangements to enable local manufacture of equipment, higher operating cost, availability of financing, limited domestic availability of required engineering, materials and O&M capabilities, and suitability of coal properties. The State Development and Planning Commission of PR China approved a project for demonstration of a 300-400 MW coal-fired IGCC power plant at the Yantai power plant located in Shandong Province. Prefeasibility studies and comparisons with other advanced energy options for the project began in 1994, followed by studies of alternative site locations, tours to IGCC demonstration projects and in-depth investigations of gasification technologies offered by Texaco, Destec, Shell and Prenflo, as well as GE and Siemen's gas turbines (Jiang and Zhao, 1998; Xu, 2000). Evaluation of bids for the project will be done in 2002, while startup is planned for 2004-2005.

Scenarios E18 and E19 assume repowering of existing oil/gas or coal fired conventional plants with a CHP facility capable of displacing the electricity and heat/cooling load previously met by separate systems. An IPCC (2001a) study concludes that the most important obstacles to expanded use of CHP technology in developing economies are information barriers, the decentralized character of the technology, the terms of the grid connection for electricity and energy policy. To this list can be added the load characteristics of the host and the influence these have on the reliability and power output capabilities of the plant. Information barriers include inadequate technical expertise for evaluation and design of CHP, uncertainty about fuel prices and availability, regulatory conditions and other information needed to apply the technology. Terms of the grid connection may not be favourable to a CHP. These are determined by the policy and attitude of the existing power provider, regulatory complexities to arrange for a grid connection and technical specifications for the delivered electricity. Effective integration of CHP technologies into the national power supply requires good long-term planning and supportive energy policies and regulations.

8. CONCLUSIONS

ENERGY USE, ELECTRICITY GENERATION AND CO_2 EMISSIONS

- Compared to world totals, APEC economies account for 64% of the global economic activity, 42% of the population, 61% of the generated electricity and 59% of the carbon dioxide emissions.

- In the APEC region in 1998, fossil fuels were used to generate 5,851,351 GWh of electricity and cogenerated heat (IEA data) using 1,316,747 MW of installed capacity (APEC data). Fossil fuel combustion for electricity and combined heat generation resulted in 5,487.6 Mt of CO_2 emissions (IEA data), which is equivalent to an overall CO_2 emission intensity of 938 gCO_2/kWh.

- In 1998, approximately seventy percent of the total generating capacity in the APEC region (1,887,448 MW) was thermal power, fired using fossil fuels, while hydropower had 19% of the capacity, nuclear 10% and other fuels comprising less than 1%. Total generating capacity grew approximately 1.1% from 1998 to 1999, based on data for all APEC economies except Russia and Papua New Guinea, for which 1999 data are not available.

- Based on the UDI database of power plants as of November 2000, the thermal electricity generating capacity in the APEC region is 51% fuelled by coal, 30% by natural gas, 19% by oil, highlighting the importance of coal in the fuel mix profile used for electricity generation. The thermal generating capacity in the APEC region according to the UDI database (November, 2000) is 1,325,563 MW.

- Electricity consumption in the APEC region is forecast to grow at an annual average rate of 2.8% per year over the period from 1999 to 2020 and this will result in a 79% increase above an already very large current electricity consumption. Without improvements in energy efficiency or changes in fuel mix, this growth in electricity consumption would result in the same percentage increases in fossil fuel consumption and CO_2 emissions.

- There is a wide range of penetration of different fossil fuel power generation technologies in the APEC economies. In the APEC region, subcritical pulverized coal burner technology is used on 76% of the coal-fired generating capacity, with supercritical PC burner technology following second at 18%. Subcritical boiler/steam turbine technology and simple cycle gas turbines power 50% and 12% of the oil-fired capacity, respectively. For gas-fired capacity, the dominant technology is subcritical boiler/steam turbine technology, which is used for 41% of the capacity, followed next by either combined cycle gas turbine or combined heat and power plants at 26%.

- Available data on future power plants under construction or already planned for the APEC region indicate that current generating capacity will increase by 42%. Of this committed and planned expansion, 37% will occur in PR China, 24% in the United States, 12% in Japan, 5% in Russia and 4% in Korea, for a total of 82% in these five economies. Although by no means exact and possibly under-representing data for some of the developing economies, these statistics suggest that the majority of growth in electricity generating capacity will be split among a relatively small number of economies and that total capacity growth will occur perhaps 40% in developed economies and 60% in developing economies.

- IEA data for 1998 show that national CO_2 emissions from the electricity generation sector vary from a low of 497 gCO_2/kWh in New Zealand to a high of 1,325 gCO_2/KWh in Russia, with an overall average for the APEC region of 938 gCO_2/kWh. The CO_2 emission factor for the electricity generation sector in the United States is 876 gCO_2/kWh and the factor for PR China is 1,202 gCO_2/kWh.

OPTIONS TO IMPROVE EFFICIENCY AND REDUCE CO_2 EMISSIONS

- Power plants using pulverized coal burners and supercritical steam pressures are the most efficient (40-46% LHV) and lowest CO_2 emitting, commercially proven technology for coal. Near commercial PFBC and IGCC technologies can achieve higher net plant efficiencies, than current commercial coal-fired technologies, with IGCC able to achieve an efficiency near 48%.

- The most efficient commercial gas-fired power plant technology presently used is based on GTCC and achieves a thermal efficiency in the range of 56% to 60%, depending on the supplier and design.

- Reduction in emissions of CO_2 from existing gas, oil and coal fired power plants can be achieved by a combination of combustion, steam cycle and operating and maintenance improvements, fuel switching, repowering with more efficiency technologies or repowering with combined heat and power cycle design. The report provides details of a wide range of potential improvements and repowering options and the benefits that can be achieved.

- Over the long-term, technologies could become commercially available to capture and sequester CO_2 emissions from fossil-fuel fired power plants. Research in CO_2 capture technology suggests about 90% of the CO_2 emissions from future advanced coal-fired and gas-fired power plants could be captured. This technology is still in the early stage of development for the power sector, however, the proposed technologies for removal of CO_2 from gas steams are well proven in the chemical and gas processing industries in similar applications. Further studies of the application of this technology in the power generation sector are needed to reduce cost and advance commercializaton of the technology.

SCENARIOS TO REDUCE CO_2 EMISSIONS

- Nineteen scenarios were identified as potential options of reducing CO_2 emissions from the existing range of fossil-fuelled energy technologies used in power plants in the APEC region. These scenarios were developed to investigate at a screening level of detail the potential reduction in emissions of CO_2 that could be achieved with assumed nominal values for the efficiency of a plant and the efficiency of the plant after application of an emission reduction option. Further site-specific analysis should be undertaken before implementing the identified emission reduction measures at a power plant.

  Scenarios E1-E5 apply to combustion, steam cycle and O&M upgrades. Scenarios E6-E11 involve switching partly or completely from the current fuel to a lower carbon fuel. Scenarios E12-E19 apply to repower situations where the existing technology is replaced with more efficient technology or a combined heat and power plant. These repowering options also can be applied in new power plants. Approximate estimates of the reduction in CO_2 emissions achievable at a suitable candidate power plant ranges from 4% to 53% when using fossil fuels, and increases in one case to 100% as a result of switching to biomass firing.

  The five highest ranked scenarios for application to coal-fired power plants are:

– E16: repower a subcritical pulverized coal, stoker or cyclone boiler with an AFBC (or other) biomass energy system firing 100% biomass (CO_2 reduction=1040 g/kWh);
– E10: switch a subcritical pulverized coal boiler to gas firing (CO_2 reduction=450 g/kWh);
– E19: repower a subcritical pulverized coal boiler with a combined heat and power system (CO_2 reduction=357 g/kWh);
– E17: repower a subcritical pulverized coal, stoker or cyclone boiler with IGCC or PFBCC; (CO_2 reduction=277 g/kWh); and
– E11: switch a subcritical pulvervized coal boiler to oil (CO_2 reduction=262 g/kWh).

The five highest ranked scenarios for application to oil/gas fired power plants:

– E13: repower a simple cycle gas turbine to a combined cycle (CO_2 reduction=483 g/kWh);
– E12: repower a subcritical boiler/steam turbine plant with GTCC (CO_2 reduction=254 g/kWh);
– E18: repower a subcritical boiler/steam turbine plant with combined heat and power system (CO_2 reduction=229 g/kWh);
– E3: apply combustion, steam cycle and O&M improvements to gain a 5% point increase in net efficiency for a simple cycle gas turbine plant (CO_2 reduction=148 g/kWh); and
– E9: switch an oil-fired subcritical boiler to gas-fired (CO_2 reduction=142 g/kWh).

- An order of magnitude estimate of the CO_2 emission reduction that could be achieved in the APEC region was developed by applying the identified CO_2 reduction scenarios to the existing capacity of power plants in applicable groups of fuels and technologies. The analysis is based on simplified assumptions for the extent of application to existing power plant capacity for the APEC region as a whole, and the results should therefore be used with recognition of the limitations of this simplified approach. The analysis makes allowance for the combined effect of the emission reduction achievable with the identified option, the total existing capacity of plants suited to application of the reduction option, and an assumed level of penetration of the Scenario. Consequently, some of the best performing options are different than discussed above for application to individual plants.

  The five scenarios with the highest estimated order of magnitude reduction in annual CO_2 emissions are:

– E4: apply combustion, steam cycle and O&M improvements to gain a 3.5% point increase in net efficiency for a coal fired power plant;
– E16: repower a subcritical pulverized coal, stoker or cyclone boiler with an AFBC (or other) biomass energy system firing 100% biomass;
– E10: switch a subcritical pulverized coal boiler to gas firing;
– E15: repower a subcritical pulverized coal, stoker or cyclone boiler with an AFBC (or other) biomass energy system firing 20% biomass;
– E14: repower a subcritical pulverized coal power plant with a supercritical pulverized coal power plant.

- The most promising CO_2 emission scenarios for the five APEC economies with the largest CO_2 emissions from the power generating sector are outlined in Section 5.3.2, namely, the United States, PR China, Russia, Japan and Australia.

ENVIRONMENTAL CO-BENEFITS OF CO_2 EMISSION REDUCTION

- Implementation of CO_2 reduction options in the APEC region will also result in reductions in emissions of particulate matter, NO_x, SO_x, CO and VOC for all fossil fuels. These options would reduce emissions of hazardous air pollutants from coal fired power plants, with reductions in mercury emissions being most significant. The associated reduction in emissions of common and hazardous air pollutants will improve local and regional air quality in the vicinity of existing power plants and help to alleviate problems with long-range transport and acid rain that are commonly associated with power plant emissions in the APEC economies. The savings in health related damages resulting from improved air quality should be factored into analysis of the cost effectiveness of CO_2 reduction options.

- The change in pollutant emissions achievable with each of the identified CO_2 emission reduction scenarios was determined qualitatively for the pollutants of primary concern, as discussed in Chapter 6 of this study. Scenarios involving combustion, steam cycle and operating and maintenance improvements are anticipated to yield small reductions in pollutant emissions, in proportion to the change in plant efficiency. Fuel switching to 100% natural gas could yield substantial reductions in emissions and is attractive for this reason where air quality is poor and fuel switching is a viable option. Implementation of high efficiency technologies for coal offer substantial emission reduction benefits as a result of the increase in fuel efficiency, combined with improved pollution control that is integral to the current advanced systems. The environmental co-benefits (i.e., reduction in emissions of common and hazardous pollutants) from repowering with CHP technology are higher for coal firing than oil/gas firing, because of the differences in emission from existing power plants using these fuels.

DATA GAPS AND AREAS NEEDING FURTHER STUDY

- The results of this study suggest further work is needed in the following areas to fill data gaps and facilitate implementation of effective CO_2 emission reduction strategies for the electricity generation sector in the APEC region:

  – identify barriers and means of reducing the barriers to accelerated adoption of supercritical and ultra supercritical boiler technology and advanced clean coal technologies in developing economies;

  – for economies experiencing rapid growth in electricity generation, conduct detailed studies of the costs and benefits of implementing the more promising CO_2 emission reduction measures identified in this study;

  – demonstrate the application of a range of combustion, steam cycle and O&M improvements, such as included in Scenario E4, in a developing APEC economy to quantify the improvements achieved (i.e., CO_2, common pollutants and performance), identify problems encountered and develop instructional and training materials needed to apply these techniques in other similar APEC economies; and

  – investigate regulatory reforms and non-technical CO_2 emission reduction measures that are needed to support or enhance the implementation of more efficient energy technologies in the APEC region, such as those identified in this study.

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Appendix A Survey Questionnaire Form

ASIA-PACIFIC ECONOMIC COOPERATION (APEC)

ENERGY WORKING GROUP

EXPERT'S GROUP ON CLEAN FOSSIL ENERGY

CO_2 REDUCTION OPTIONS FOR UTILITY ELECTRICITY GENERATION IN THE APEC REGION

PROJECT 04/2000

Introduction

The APEC Expert's Group on Clean Fossil Energy promotes the use of clean fossil fuels and advanced conversion technologies that will increase energy efficiency and reduce environmental impacts of fossil fuel use.

This questionnaire is being sent to gather essential data from APEC member economies that will form the foundation for identification and analysis of options for reducing CO_2 emissions from the utility electricity generation sector. Data is requested regarding current fuels and technologies being used, forecast additional future electricity requirements and generation technologies, and options and policies that are being implemented, or are of interest to reduce CO_2 emissions.

The participation of the APEC member economies and the assistance of individuals providing data in response to this questionnaire are gratefully acknowledged. Organizations which respond to this questionnaire will be provided with a complimentary copy of the study report.

The APEC contact to obtain additional background information for this study is Mr. Kenneth Leong Hong, who can be reached by email using the address: kenneth.hong@HQ.DOE.GOV

General Instructions:

The questionnaire consists of three worksheets, with individual tabs below. Each worksheet is focused on different information. The worksheets are: Existing Power Plants; Future Power Plants; and CO_2 Reduction Options. Please make a copy of this Excel file, then enter your data directly into the shaded areas. When done, email the file back to us at the address below. The form can also be printed and faxed or mailed. Insert more rows in each worksheet as required to fit your data.

We want to involve the most appropriate organizations and utitlity companies in providing the information requested for this study so that the best possible information can be obtained for all the APEC economies. Please forward this questionnaire to others you think could provide data, or advise us of the names and addresses of other contacts who we should contact.

Return or Clarification of Questionnaire

Please return the completed questionnaire by email (preferred), fax, or mail to:

Wayne Edwards, P.Eng.

email address: apec@levelton.com

Telephone : (604) 278-1411   Fax : (604) 278-1042

Levelton Engineering Ltd., Unit 150, 12791 Clarke Place

Richmond, British Columbia, CANADA, V6V 2H9

If you have any questions about the data requested, please contact Wayne Edwards by email or fax and answers will be provided promptly.

For timely completion of the study, it is important that all questionnaires be completed and returned by May 15, 2001. Thank you in advance for your cooperation and assistance.

Economy:		Person:		Email:	
Organization:		Tel:		Fax:	

Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design (Group by Efficiency and Design)		Combined Data for Each Plant Group					
		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low							
(<25%)							
Moderate							
(25%-40%)							
High							
(>40%)							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	0	0		0	
Natural Gas							
Low							
(<25%)							
Moderate							
(25%-40%)							
High							
(>40%)							
# boiler,gas turbine, simple cycle, combined cycle, cogeneration,		Totals	0	0		0	
Light & Heavy Fuel Oil							
Low							
(<25%)							
Moderate							
(25%-40%)							
High							
(>40%)							
# boiler, gas turbine, simple cycle, combined cycle, cogeneration,		Totals	0	0		0	
Biomass							
Low							
(<25%)							
Moderate							
(25%-40%)							
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	0	0		0	
Hydroelectric							
Nuclear							
Other							
(describe)							
		Totals	0	0		0	
Total of listed energy sources			0	0		0	

Economy:		Person:		Email:	
Organization:		Tel:		Fax:	

A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Base year for power capacity growth:

Describe Design (See # below for examples)	By 2005		By 2010		By 2020	
	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)
Coal						
Oil						
Natural gas						
Biomass						
Hydroelectric						
Nuclear						
Other: (list)						
Total all Systems	0		0		0	

# Coal	pulverized, fluidized, stoker, saturated, superheated, etc.
Natural gas	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Oil	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Biomass	pulverized, fluidized, stoker, saturated, superheated, etc.

B) Stength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.

		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.			
	Availlability of skilled labour in your region (skilled operators, trades people)			
	Availability of professionals in your region (engineers, managers, financial)			
Operational	Adequacy and sophistication of maintenance program			
	Training level of operating, maintenance and management staff			

Economy: | Person: | Email:
Organization: | Tel: | Fax:

Future Options to Reduce Green House Gas (GHG) Emissions from Existing Plants

Please check off one or more options to reduce national CO_2 emissions. For each option, separately report actual use from those of potential interest. Make your best estimates of the capacity being impacted, efficiencies for each option (if known) and other data in the table below.

Options	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity (MW)	Current Efficiency (%)	New System: New Efficiency (%)	New System: CO_2 Reduction (ktonnes/yr.)	Types of technology- please state briefly See other worksheets for examples of technology descriptions. For cogeneration of thermal energy, indicate fuel type and efficiency gain	State if (A)ctual or (P)otential
☐	**Option 1-** ***Replacement of old technology and small plants with better systems using the same fuel.***								
1	coal								
	oil								
	natural gas								
☐	**Option 2-** ***Retrofit technology for the same fuel type to improve combustion efficiency (e.g. instrumentation, new burner technology, reduced excess air, preheat air and/or water, etc.)***								
2	coal								
	oil								
	natural gas								
☐	**Option 3-** ***Increase efficiency by improving facility operation and maintenance with same equipment.***								
3	coal								
	oil								
	natural gas								
☐	**Option 4-** ***Convert to higher efficiency technology (e.g. from simple to combined cycle gas turbine, low to high pressure steam turbine, etc.)***								
4	coal								
	oil								
	natural gas								

☐ **Option 5-** ***Switch to lower carbon containing fuel using same technology (include thermal capacity for cogeneration)***

5	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity: Elect. (MW)	Capacity: Thermal (MW)	% Capacity Split According to Fuel Type: Oil	Natural gas	Biomass	Hydro	Nuclear	Other	State if (A)ctual or (P)otential
	coal											
	oil					-						
	natural gas					-	-					

☐ **Option 6-** ***Apply taxes, energy policies, emission trading or other approaches to reduce green house gas emissions.***

6	Fuel Type	Economic instruments such as taxes, incentives, emission trading, premiums for certain fuels, promotion of conversion, etc. Also, include other approaches. Please describe. Method to Promote Emission Reduction	Impacted Capacity (MW)	CO_2 Reduction (ktonnes/yr.)	State if (A)ctual or (P)otential

Appendix B Additional Figures and Tables for Chapter 3

Table B-1 Installed Electricity Generating Capacity (MW) in the APEC Economies According to the UDI Database to November, 2000

Economy	Coal	Gas	Oil	Hydro	Nuclear	Biomass	Solid Waste	Waste Gas	Zero GHG	Unknown	Grand Total
Australia	27,057	5,986	2,733	7,614		250		410	380	97	44,526
Brunei Darussalam		806	12								818
Canada	17,818	9,991	4,684	65,835	10,409	921	28	118	755	41	110,601
Chile	1,947	1,713	1,304	4,130		17			532	57	9,700
People’s Republic of China	160,413	1,231	13,767	51,846	2,269		4	202	1,225	80	231,038
Hong Kong, China	6,610	2,046	2,382					4			11,041
Indonesia	7,197	5,690	9,467	3,528		475		2	2,944	738	30,041
Japan	29,549	52,858	71,667	44,781	45,082	6	113	2,731	2,225	7,255	256,268
Republic of Korea	13,900	11,910	6,298	3,174	13,840		20	63	3,190	663	53,057
Malaysia	1,700	7,837	3,585	1,992		52	2		1,952	90	17,209
Mexico	2,600	4,872	17,850	10,104	1,349			2	2,199	375	39,352
New Zealand	1,021	1,592	433	5,512		76		88	514	31	9,269
Papua New Guinea		121	438	221							780
Peru	270	222	1,719	2,552						100	4,863
Philippines	4,258	683	7,862	2,285		66		51	2,129	50	17,385
Russia	50,782	87,946	11,706	44,651	20,237			441	1,482	11	217,256
Singapore		1,299	5,331				117	39	328		7,115
Chinese Taipei	9,218	4,279	7,970	4,657	5,148	45	256	17	2,009	708	34,307
Thailand	3,467	12,154	1,142	3,047		500	28		3,116	59	23,513
United States of America	333,528	188,343	79,202	95,662	102,470	6,430	2,802	2,654	21,670	115	832,875
Viet Nam	693	898	1,506	3,238		27				29	6,391
Grand Total	672,029	402,476	251,058	354,830	200,803	8,864	3,370	6,821	46,652	10,501	1,957,404

Source: UDI/McGraw-Hill Energy, 2000

Table B-2 Installed Electricity Generating Capacity (MW) in the APEC Economies According to the UDI Database for 1998

Economy	Coal	Gas	Oil	Hydro	Nuclear	Biomass	Solid Waste	Waste Gas	Zero GHG	Unknown	Grand Total
Australia	26,707	5,454	2,682	7,614	0	250	0	408	366	97	43,578
Brunei Darussalam	0	806	12	0	0	0	0	0	0	0	818
Canada	17,818	8,959	4,681	65,738	10,409	886	28	107	486	41	109,154
Chile	1,947	485	1,029	4,006	0	17	0	0	302	57	7,843
People's Republic of China	150,862	1,231	13,667	46,160	2,269	0	4	152	1,139	80	215,564
Hong Kong, China	6,610	2,046	2,382	0	0	0	0	4	0	0	11,041
Indonesia	4,923	5,460	9,396	3,221	0	475	0	2	2,754	738	26,970
Japan	27,714	47,798	71,172	43,862	45,082	6	113	2,689	1,774	7,249	247,458
Republic of Korea	12,180	11,816	6,298	3,174	12,078	0	20	63	2,425	663	48,716
Malaysia	700	7,578	3,502	1,992	0	52	2	0	1,934	90	15,850
Mexico	2,600	4,552	17,850	10,104	1,349	0	0	2	1,852	375	38,685
New Zealand	1,021	1,150	433	5,512	0	76	0	88	423	31	8,735
Papua New Guinea	0	121	413	221	0	0	0	0	0	0	756
Peru	0	222	1,634	2,400	0	0	0	0	0	100	4,356
Philippines	2,148	683	6,719	2,285	0	66	0	51	2,075	50	14,077
Russia	50,782	87,939	11,706	44,651	20,237	0	0	441	1,462	11	217,230
Singapore	0	1,299	4,051	0	0	0	117	39	328	0	5,835
Chinese Taipei	8,018	3,163	7,892	4,635	5,148	45	184	6	1,331	708	31,130
Thailand	2,822	9,929	1,142	3,036	0	500	28	0	2,524	59	20,038
United States of America	333,348	165,798	78,372	95,492	102,470	6,425	2,802	2,579	17,693	115	805,094
Viet Nam	693	523	1,367	2,843	0	27	0	0	0	29	5,481
Grand Total	650,894	367,013	246,402	346,948	199,041	8,824	3,298	6,630	38,867	10,494	1,878,411

Source: UDI/McGraw-Hill Energy, 2000

Table B-3 Electric Power Generation in APEC Economies from IEA Data

Economy	Electricity Generation (TWh)								
	Coal	Oil	Gas	Subtotal Fossil	Hydro	Nuclear	Other	Total	Year
Australia	156	2	17	175	16	0	3	195	1998
Brunei Darussalam	0	2	0	2	0	0	0	2	1997
Canada	107	18	26	152	332	72	6	562	1998
Chile	12	3	1	15	19	0	0	34	1997
People's Republic of China	863	83	7	953	196	14	0	1,163	1997
Hong Kong, China	28	1	0	28	0	0	0	28	1996
Indonesia	23	22	21	66	6	0	3	75	1997
Japan	198	170	218	586	103	332	25	1,046	1998
Republic of Korea	101	14	26	141	6	90	0	237	1998
Malaysia	3	6	46	55	3	0	0	58	1997
Mexico	18	101	24	143	25	9	6	182	1998
New Zealand	1	0	9	10	24	0	3	38	1998
Papua New Guinea	1	0	0	1	1	0	0	2	1999
Peru	0	4	0	4	13	0	1	18	1997
Philippines	7	19	0	27	6	0	7	40	1997
Russia	140	44	377	561	157	109	6	833	1997
Singapore	0	22	4	26	0	0	1	27	1997
Chinese Taipei	65	34	9	107	10	36	0	153	1997
Thailand	19	22	43	84	7	0	2	93	1997
United States of America	2,006	147	558	2,711	322	714	85	3,833	1998
Viet Nam	0	2	1	3	16	0	0	19	1997
All APEC	3,748	716	1,387	5,851	1,262	1,377	149	8,639	

Sources:
IEA, 1999c, Energy Statistics of OECD Countries, 1997-1998
IEA, 2000b, Energy Balances of Non-OECD Countries, 1996-1997

Table B-4 Electric Power Generation in APEC Economies from Various Data Sources

Economy	Electricity Generation (TWh)								
	Coal	Oil	Gas	Subtotal Fossil	Hydro	Nuclear	Other	Total	Year
Australia	156	1	12	170	16	0	4	190	2001
Brunei Darussalam	1	1	1	3	0	0	0	3	1999
Canada	90	15	20	125	347	78	7	557	1997
Chile	10	2	6	19	19	0	0	37	1999
People's Republic of China	860	69	2	932	214	14	0	1,160	2001
Hong Kong, China	17	0	10	28	0	0	0	28	2001
Indonesia	39	14	12	64	6	0	3	73	1999
Japan	184	119	297	600	85	309	25	1,018	2001
Republic of Korea	93	21	34	148	4	98	0	250	2001
Malaysia	7	15	33	54	3	0	0	57	1999
Mexico	18	100	17	135	32	10	5	182	2001
New Zealand	0	8	2	10	24	0	3	36	1999
Papua New Guinea	1	0	0	1	1	0	0	2	1999
Peru	0	2	1	4	14	0	0	19	2001
Philippines	13	12	0	25	8	0	8	41	2001
Russia	89	114	284	487	150	98	36	772	1999
Singapore	9	4	13	26	0	0	0	26	1999
Chinese Taipei	71	1	16	88	10	35	0	134	1999
Thailand	15	16	55	87	3	0	0	90	1999
United States of America	1,881	127	527	2,535	318	674	68	3,596	1998
Viet Nam	0	2	1	3	18	0	0	21	1999
All APEC	3,556	643	1,345	5,544	1,274	1,315	158	8,291	
World	4,633	1,363	2,589	8,584	2,567	2,315	208	13,674	
APEC's portion of World Amounts	76.75%	47.20%	51.94%	64.58%	49.62%	56.81%	57.59%	60.79%	
World Distribution of energy	33.88%	9.96%	18.93%	62.78%	18.77%	16.93%	1.52%		

Sources for Total Energy:
www.odci.gov/cia/publications/factbook
Canada's Emissions Outlook (Energy Sector Can-14)
http://www.epa.gov/airmarkets/egrid/index.html
2001 Electricity Supply Association of Australia Ltd
EGAT National Energy Policy Office http://www.nepo.go.th/info/NB-T12.html

Sources for Fossil fuel energy split:
Individual Country responses to Survey
Based on UDI/McGraw-Hill Energy Capacity split ratio per country.

Table B-5 Summary of 1998 Carbon Dioxide Emissions from Fossil Fuel Combustion

Economy	CO_2 emissions (Mt)				
	Power & Heat Generation *			Other Fossil Fuel Combustion	Total Fossil Fuel Combustion
	Coal	Oil	Gas		
Australia	153.7	1.6	8.3	153.7	317.2
Brunei Darussalam	0.0	0.0	2.1	2.8	4.9
Canada	97.4	12.1	12.9	377.3	499.6
Chile	11.2	1.8	1.9	37.1	51.9
People's Republic of China	1,081.1	59.6	4.8	1,660.6	2,806.1
Hong Kong, China	17.2	0.2	5.1	17.6	40.1
Indonesia	25.4	12.1	13.0	176.0	226.5
Japan	185.9	97.5	95.8	720.1	1,099.3
Republic of Korea	117.0	11.0	11.5	226.0	365.5
Malaysia	1.5	8.2	19.2	63.5	92.4
Mexico	16.6	70.6	13.7	250.7	351.6
New Zealand	1.3	0.0	3.8	22.8	27.8
Papua New Guinea					
Peru	0.5	3.1	0.0	21.2	24.8
Philippines	3.7	15.5	0.0	42.8	62.0
Russia	248.7	107.3	387.0	592.7	1,335.6
Singapore	0.0	13.7	3.3	26.4	43.5
Chinese Taipei	63.9	20.5	6.7	99.0	190.1
Thailand	16.7	13.9	24.2	93.4	148.1
United States of America	1,919.8	123.1	331.7	3,058.7	5,433.3
Viet Nam	5.3	2.5	1.6	23.6	32.9
Total APEC	3,966.6	574.4	946.6	7,665.8	13,153.2
World	5,836.0	1,043.2	1,495.7	13,994.3	22,369.2

* Includes electricity and heat from public utilities and autoproducers (for own use), as defined by the IEA.
Source: IEA, 2000a

Table B-6 Summary of 1998 Electricity Generation and CO_2 Emissions per GWh

Economy	Energy from Power Generation (GWh)				t CO_2/GWh (all fossil)
	Coal	Oil	Gas	All Fossil Fuels	
Australia	155,544	2,233	17,423	175,200	934
Brunei Darussalam	0	2,407	0	2,407	860
Canada	107,421	18,401	26,085	151,907	805
Chile	11,506	2,608	730	14,844	999
People's Republic of China	863,134	83,224	6,657	953,015	1,202
Hong Kong, China	27,880	562	0	28,442	792
Indonesia	23,001	22,447	20,816	66,264	761
Japan	198,035	169,955	218,343	586,333	647
Republic of Korea	100,785	14,322	26,302	141,409	987
Malaysia	3,050	5,906	45,625	54,581	530
Mexico	17,828	101,035	23,940	142,803	707
New Zealand	1,463	0	8,700	10,163	497
Papua New Guinea	1,000	0	0	1,000	
Peru	0	3,724	331	4,055	885
Philippines	7,363	19,129	13	26,505	723
Russia	139,629	44,013	377,000	560,642	1,325
Singapore	0	21,758	4,430	26,188	651
Chinese Taipei	65,151	33,505	8,802	107,458	848
Thailand	18,925	21,790	43,179	83,894	652
United States of America	2,006,328	147,173	557,772	2,711,273	876
Viet Nam	0	2,049	919	2,968	3,130
Total	3,748,043	716,241	1,387,067	5,851,351	938

Source: Electricity generation data from:
IEA, 2000b, Energy Statistics of OECD Countries, 1997-1998
IEA, 1999c, Energy Balances of Non-OECD Countries, 1996-1997

Table B-7 Summary of Survey Responses for Power Plant Capacities by Technology

Fuel	Technology	Power Plant Capacity (MW)					
		Mexico	Japan	Korea	Peru	Philippines	Hong Kong
Coal	Steam Subcritical	2,600	14,579	13,031	0	1,305	6,608
	Steam Supercritical	0	13,012	0	135	0	0
Gas	IC Engine	0	0	0	38	0	0
	GTSC	2,600	0	1,374	293	0	0
	GTCC	2,251	23,329	10,935	0	0	1,872
	Steam Subcritical	0	33,279	0	0	0	0
	Steam Supercritical	0	0	0	0	0	0
Oil	IC Engine	91	0	0	1,204	428	0
	GTSC	15,142	0	4,611	261	295	1,114
	GTCC	212	0	0	21	620	0
	Steam Subcritical	2,100	48,860	0	1,230	300	0
	Steam Supercritical	0	613	0	0	1,000	0
Hydro		9,619	0	3,148	2,860	1,847	0
Nuclear		1,368	45,082	13,716	0	0	0
Biomass		0	0	0	25	0	0
Geothermal/Wind		852	0	0	0	0	0
Geothermal		0	0	0	0	1,283	0

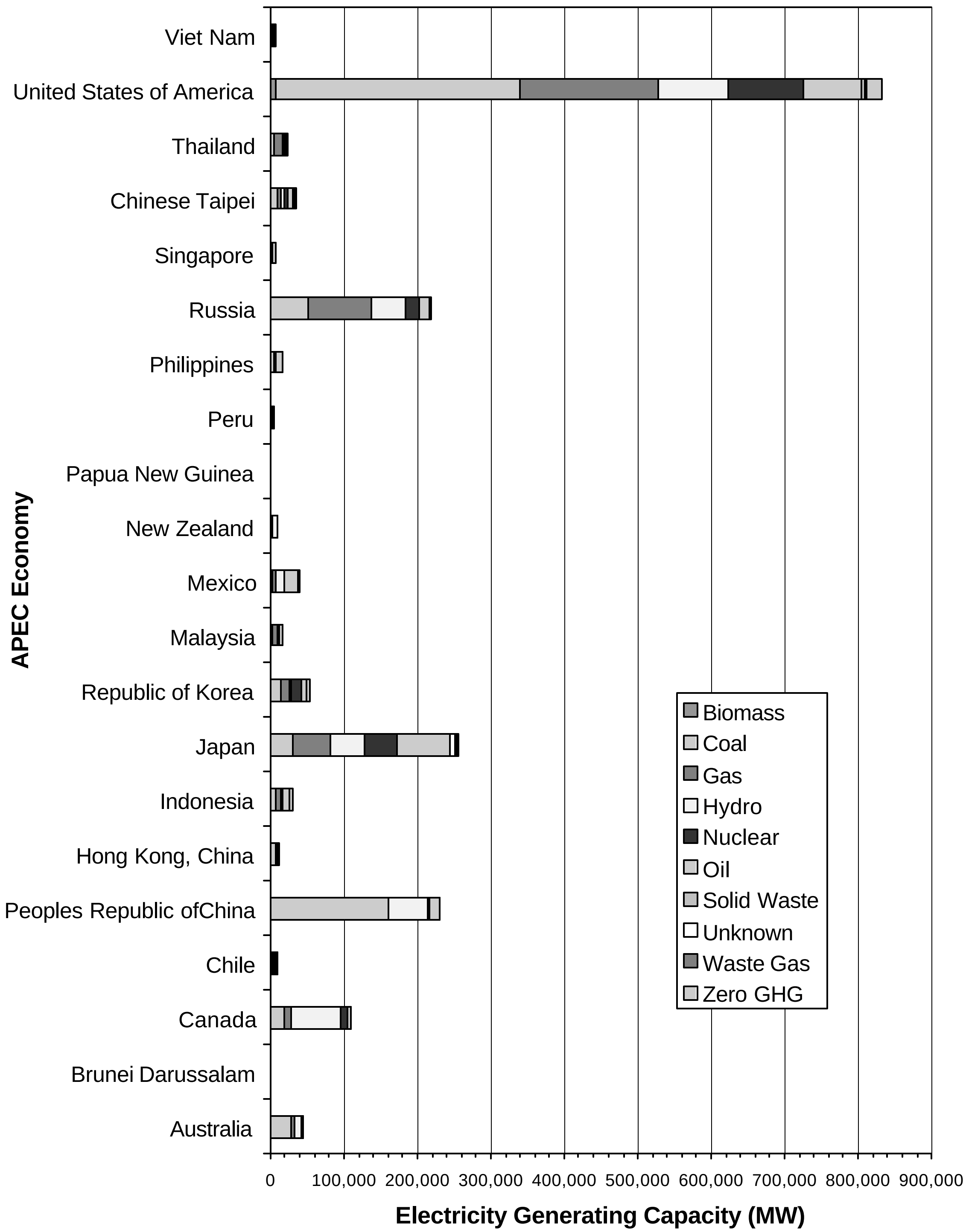

Figure B-1 Electricity Generating Capacity for APEC Economies to November, 2000

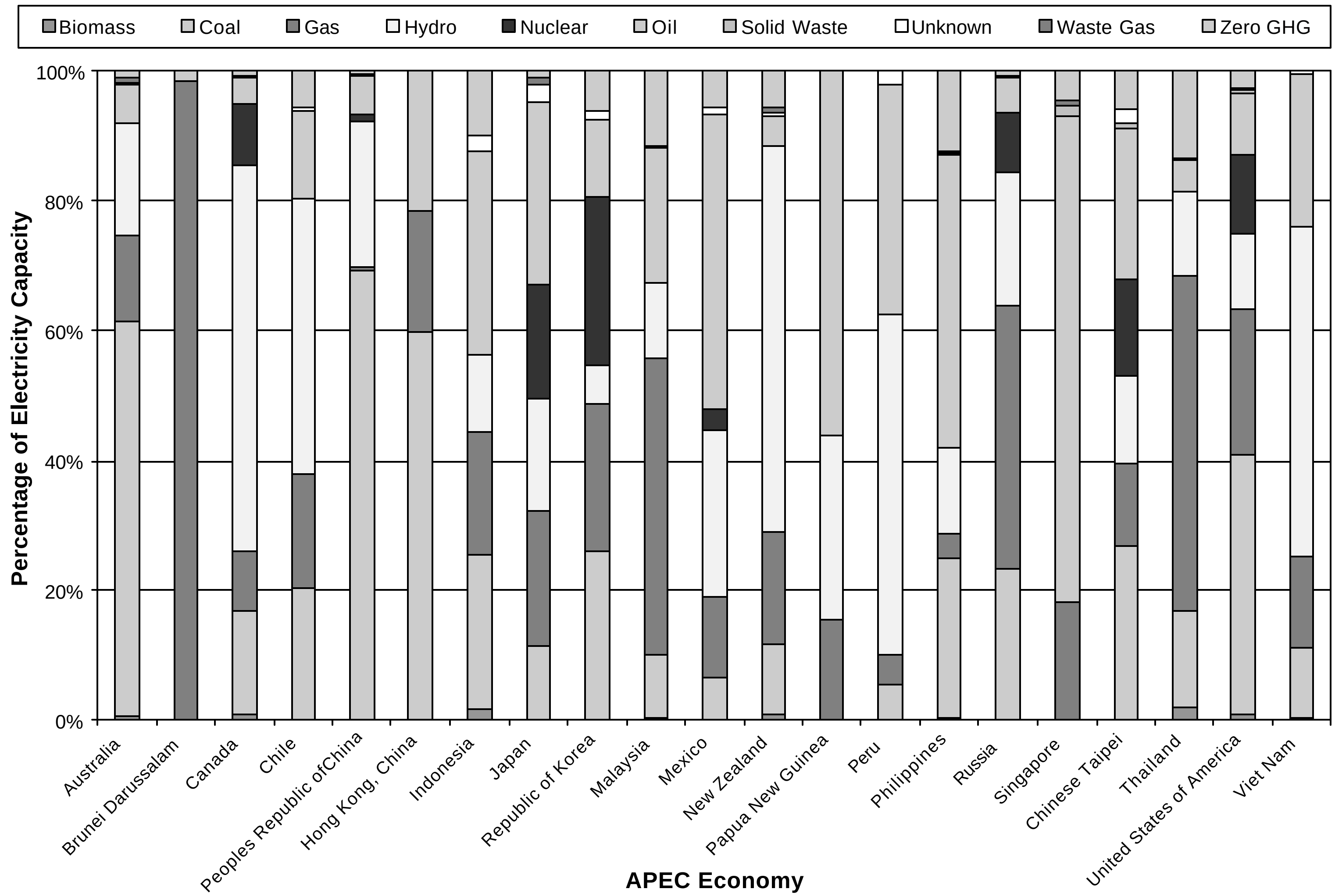

Figure B-2 Distribution of Generating Capacity by Fuel Type from the UDI Database to November, 2000

Appendix C Completed Survey Forms from APEC Economies

Economy: MEXICO Person: Email:

Organization: CFE & LFC Tel: Fax:

Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design			Combined Data for Each Plant Group					
(Group by Efficiency and Design)			Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)		years	MW	Quantity	Units	GWh	%
Coal								
Low (<25%)								
Moderate (25%-40%)	Superheated		18 a 4	2,600	9,792,387.83	Tonnes	17,326.22	34.29
High (>40%)								
# pulverized, fluidized, stoker, saturated, superheated, etc.			Totals	2,600	9,792,387.83		17,326.22	
Natural Gas								
Low (<25%)	Gas Turbine	Monclova	25-20	48	47,746.00	10^3 m^3	93.52	21.09
		Universidad	30-29	24	30,234.00	10^3 m^3	54.33	19.35
		Leona	28	24	30,629.00	10^3 m^3	54.47	19.15
		Fundidora	29	12	14,776.00	10^3 m^3	26.65	19.42
		Jorge Luque (Lechería)	28-23	138	61,706.00	10^3 m^3	140.07	24.45
		Valle de México	28	88	18,383.00	10^3 m^3	40.42	23.68
Moderate (25%-40%)	Gas Turbine	Hermosillo	2	132	128,542.00	10^3 m^3	359.99	30.16
		Nonoalco	28-25	148	63,163.00	10^3 m^3	147.85	25.21
		Huinalá	1	140	256,060.00	10^3 m^3	813.65	34.22
		Emilio Portes (TG Río Bravo)	1	145	359,251.00	10^3 m^3	1,089.98	32.68
		Sauz TG	2	122	206,816.00	10^3 m^3	642.66	33.47
		Pueblo nuevo			10,053.00	10^3 m^3	24.95	26.73
	Combined cycle	Gómez Palacio	25	200	374,858.00	10^3 m^3	1,190.73	34.21
		Francisco Pérez Ríos (Tula)	19-16	482	708,460.00	10^3 m^3	2,598.14	39.50
		El Sauz	19-14	218	406,402.00	10^3 m^3	1,461.15	38.72
		Dos Bocas	25-26	452	745,344.00	10^3 m^3	2,566.76	37.09
	Simple Cycle Gas	La Laguna	33	39	73,060.00	10^3 m^3	176.70	26.05
		San Jerónimo	39	75	129,208.00	10^3 m^3	330.19	27.52
		Jorge Luque	48-40	224	240,772.00	10^3 m^3	596.10	26.66
High (>40%)	Combined cycle	Samalayuca II	2	522	897,871.35	10^3 m^3	3,942.46	47.29
		Huinala	19-15	378	667,880.00	10^3 m^3	2,574.93	41.52
# boiler,gas turbine, simple cycle, combined cycle, cogeneration, etc.			Totals	3,610	5,471,214	10^3 m^3	18,926	
Light & Heavy Fuel Oil								
Low (<25%)	Internal Combustion Diesel	Villa Constitución	29-25	10	19.29	10^3 m^3	38.91	20.15
		Santa Rosalía	33-18	9	18.36	10^3 m^3	45.43	24.72
		Nuevo Nogales			3.94	10^3 m^3	9.47	24.03
	Gas Turbine Diesel	Mexicali	24-23	62	16.10	10^3 m^3	31.76	19.71
		Ciprés	19	55	12.35	10^3 m^3	27.23	22.03
		Punta prieta (La Paz)	23	43	20.12	10^3 m^3	38.99	19.36
		Cabo San Lucas (Los Cabos)	12	30	33.29	10^3 m^3	77.51	23.27
		Caborca Industrial	19-17	42	24.30	10^3 m^3	52.87	21.74
		Ciudad Obregón II	28	28	15.74	10^3 m^3	30.59	19.42
		Parque	26-20	87	29.16	10^3 m^3	65.20	22.34
		Chihuahua	20	64	31.57	10^3 m^3	62.72	19.85
		Industrial (Juárez)	23	18	6.77	10^3 m^3	15.52	22.90
		Tecnológico	27	26	20.39	10^3 m^3	44.11	21.62
		Arroyo del Coyote	20	24	16.44	10^3 m^3	30.82	18.73
		Esperanzas	29	12	9.58	10^3 m^3	19.18	20.01
		Las Cruces	31-27	43	18.54	10^3 m^3	39.27	21.16
		Cancún	27-26	102	66.07	10^3 m^3	151.17	22.86
		Mérida II	19	30	2.37	10^3 m^3	4.50	19.03
		Nachi-Cocóm	13	30	41.16	10^3 m^3	79.59	19.32
		Ciudad del Carmen	14	14	9.70	10^3 m^3	17.47	17.99
		Xul-ha	31-20	14	12.03	10^3 m^3	22.17	18.42
		Cozumel	30-28	28	26.44	10^3 m^3	54.71	20.68
	Gas Turbine Diesel and Gas	Presidente Juárez (Tijuana, RosaritoVII	36-8	210	195,513.72	10^3 m^3	272.53	29.51
	Simple Cycle	Guaymas I	38-30	70	77.73	10^3 m^3	198.71	22.89

	Internal Combustion Diesel	Guerrero Negro	34-15	3	11.86	10^3 m^3	34.82	29.34
		Yécora	23-13	1	0.55	10^3 m^3	1.68	30.63
	Internal Combustion Fuel Oil	Puerto San Carlos	8 a 9	65	58.07	10^3 m^3	288.06	30
	Gas turbine Diesel	Ciudad Constitución	16	33	12.58	10^3 m^3	42.36	33.64
		Culiacán	20	30	14.73	10^3 m^3	36.94	25.05
		Nizuc	19	88	15.93	10^3 m^3	41.84	26.24
	Gas Turbine Diesel and Gas	La Laguna	30-24	56	55,102.45	10^3 m^3	106.54	20.61
		Chávez	29	28	20,095.23	10^3 m^3	38.53	20.43
	Simple Cycle Fuel Oil	Poza Rica	37	117	209.58	10^3 m^3	633.16	27.05
		Punta Prieta II	21-15	113	203.42	10^3 m^3	627.44	27.62
		Puerto Libertad	15 a 11	632	915.47	10^3 m^3	3,423.03	33.48
		Mazatlán II	25 a 11	616	913.55	10^3 m^3	3,257.09	31.93
		Guaymas II	27-20	484	722.33	10^3 m^3	2,556.52	31.69
		Topolobampo	32-5	360	537.25	10^3 m^3	2,018.61	33.65
Moderate *(25%-40%)*		Guadalupe Victoria (Lerdo)	11	320	541.81	10^3 m^3	2,050.11	33.88
		Manzanillo I	18	1,200	1,203.81	10^3 m^3	4,890.65	36.38
		San Luis Potosi (Villa de Reyes)	14	700	1,214.69	10^3 m^3	4,657.70	34.34
		Tuxpan	9 a 2	2,100	3,505.23	10^3 m^3	14,230.66	36.36
		Campeche II (Lerma)	26 a 11	150	317.83	10^3 m^3	950.06	26.77
		M Alvarez M (Manzanillo II)	18-16	700	1,850.38	10^3 m^3	7,208.28	34.88
	Simple Cycle Fuel Oil and Gas	Samalayuca	15	316	455.78	10^3 m^3	1,597.16	31.38
		Monterrey	37-26	465	963.41	10^3 m^3	2,705.90	25.15
		Emilio Portes Gil (Río Bravo)	36-18	375	633.28	10^3 m^3	2,082.32	29.45
		Francisco Pérez Ríos (Tula)	18	1,500	2,536.89	10^3 m^3	9,566.33	33.77
		Salamanca	30-23	866	1,425.88	10^3 m^3	5,262.31	33.05
		Valle de México	37-27	750	1,380.96	10^3 m^3	4,342.58	28.16
		Altamira	26-22	800	1,229.94	10^3 m^3	4,425.02	32.22
		Francisco Villa (Delicias)	36-18	399	708.06	10^3 m^3	2,385.46	30.17
		Mérida II	19-18	168	317.59	10^3 m^3	1,017.97	28.70
		Felipe Carrillo Puerto (Valladolid)	18 a 8	75	121.70	10^3 m^3	378.01	27.82
		Presidente Juárez (Tijuana)	36-8	620	722.00	10^3 m^3	2,366.21	29.35
	Combined cycle Fuel oil	Valladolid	9 a 6	212	172.23	10^3 m^3	619.88	32.23
	Dual (Fuel Oil and Coal)	Petacalco	7 a 6	2,100	3,166.52	10^3 m^3	12,713.23	35.95
High *(>40%)*								
# boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.			Totals	17,541	297,424		98,257	
Biomass								
Low *(<25%)*								
Moderate *(25%-40%)*								
High *(>40%)*								
# pulverized, fluidized, stoker, saturated, superheated, etc.			Totals	0	0.00		0.00	
Hydroelectric			4 a 90	9,619			32,623.40	
Nuclear			10 a 4	1,368			7,895.30	
Other (describe)		Wind and Geothermal	27 a 6	852			5,628.60	
			Totals	852	0.00		5,628.60	
Total of listed energy sources				35,590	15,561,026.50		180,656.67	

Note:The plant age is the oldest and the newest.

There are 149 MW in gas turbine and internal combustion for emergency.

The plants wich have 2 fuels (like gas and fuel oil) are reported in equivalents.

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Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design (Group by Efficiency and Design)		Combined Data for Each Plant Group					
		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low							
(<25%)							
Moderate		24	250	475,027	t	1,027	37.57
(25%-40%)		33	350	698,399	t	1,448	37.69
		21	1,035	2,345,024	t	6,916	39.42
		42	525	887,034	t	2,872	39.17
		40	281	626	t	1,773	37.71
		2	250	77	t	202	34.31
		15	1,000	2,540	t	7,564	39.84
		34	175	441	t	1,185	38.29
		18	406	961,793	t	2,658	37.7
		2	700	180,521	t	555	38.8
		41	156	321,570	t	894	37.97
		37	156	222,700	t	463	35.26
		12	700	1,494,202	t	4,403	39.88
		6	700	504,653	t	1,465	39.02
		0	360	88,182	t	228	39.06
		7	312	821,755	t	2,379	39.39
		34	530	854,286	t	2,325	38.34
		33	500	905,382	t	2,313	37.56
		34	1,300	2,625,785	t	7,254	39.16
		20	1,000	1,870,511	t	4,832	37.73
		31	1,450	1,408,169	t	6,324	37.51
		32	43	37,936	t	142	36.84
		42	150	412,537	t	1,100	36.36
		24	700	3,985	t	3,985	37.95
		30	500	1,153,144	t	3,314	37.31
		11	1,050	67,387	t	232	39.47
High		8	1,200	2,585,848	t	7,816	40.56
		4	2,000	4,262,773	t	13,080	42.21
		10	2,100	5,080,792	t	15,091	40.15
		10	1,200	1,433,299	t	4,382	40.22
		6	1,200	2,682,526	t	8,082	40.33
		3	1,000	2,584	t	8,090	42.59
		15	312	806,214	t	2,218	40.24
		11	2,000	4,449,387	t	13,137	40.89
(>40%)		6	2,000	4,503,783	t	13,417	40.51
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	27,591	44,150,872	t	153,166	

Natural Gas							
Low							
(<25%)							
Moderate		35	500	298,707	t	1,626	35.81
		28	600	255,609	t	1,501	36.39
		31	1,150	1,041,647	t	5,914	37.14
		38	1,886	1,424,177	t	8,400	39.03
		34	3,600	1,297,492	t	13,750	38.07
		27	3,600	2,982,834	t	17,664	39.1
		40	1,050	761,246	t	4,359	37.86
		21	2,600	142,264	t	6,489	38.85
		14	2,000	1,505,592	t	9,034	39.67
		35	3,966	2,175,592	t	15,552	37.46
		18	1,708	1,210,797	t	7,256	39.49
		38	1,220	462,293	t	3,598	39.55
		34	2,000	1,551,543	t	2,000	36.48
		11	1,800	1,300,925	t	7,636	38.67
		42	156	33,713	t	179	34.89
		38	2,550	1,392,065	t	8,434	37.83
		40	2,112	994,365	t	5,644	37.36
(25%-40%)		30	781	370,796	t	4,233	36.67
High		24	3,795	3,473,615	t	22,121	41.78
		3	2,160	1,431,581	t	11,739	48.72
		38	4,025	2,807,684	t	19,809	46.46
		15	2,000	1,666,655	t	10,580	41.97
		12	4,700	3,512,183	t	24,513	46.06
		3	1,458	1,109,593	t	8,101	48.11
		6	1,496	1,206,978	t	8,679	47.47
		9	1,400	1,196	t	8,036	44.42
(>40%)		9	2,295	1,499,288	t	10,240	45.1
# boiler,gas turbine, simple cycle, combined cycle, cogeneration,		Totals	56,608	35,910,429	t	247,087	
Light & Heavy Fuel Oil							
Low							
(<25%)							
Moderate		28	250	260,645	m^3	1,107	38.68
		23	250	398,139	m^3	1,744	38.68
		18	350	308,745	m^3	1,375	38.83
		33	500	269,031	m^3	1,287	35.74
		31	1,650	303,418	m^3	3,309	36.49
		30	350	213,319	m^3	916	37
		37	2,630	608,817	m^3	3,642	35.78
		30	4,400	1,844,687	m^3	8,067	38.72
		21	600	196,882	m^3	845	37.97
		30	2,400	949,402	m^3	3,919	37.84
		35	1,345	805,745	m^3	3,367	37.52
		31	2,190	611,211	m^3	2,548	37.55
		37	440	9,233	m^3	35	34.85
		37	1,250	504,723	m^3	2,547	36.73
		14	156	331	m^3	1	37.66
		37	812	328,141	m^3	1,364	36.1

		28	350	195,043	m^3	822	36.06
		27	1,000	301,716	m^3	1,246	36.81
		28	312	7,039	m^3	29	35.23
		32	156	733	m^3	3	34.18
		42	312	336	m^3	1	33.8
		46	266	593	m^3	2	27.6
		31	2,100	1,046,448	m^3	4,492	39.21
		30	900	204,685	m^3	851	38.1
		38	468	12,118	m^3	50	36.2
		45	462	1,862	m^3	7	33.49
		24	1,200	283,818	m^3	1,230	39.37
		19	1,125	42,607	m^3	168	36.15
		17	1,800	418,707	m^3	1,874	38.52
		14	1,200	508,603	m^3	2,255	38.65
		12	750	56,511	m^3	248	38.17
		28	350	17	m^3	64	34.06
		30	1,200	1,141	m^3	5,048	37.97
		29	850	144	m^3	600	36.07
		28	1,075	219	m^3	922	35.88
		24	400	376	m^3	1,634	37.27
		38	1,245	893,412	m^3	3,935	38.22
		30	1,345	708,488	m^3	4,742	37.86
		30	875	32,995	m^3	134	31.47
		32	500	10,528	m^3	44	31.13
		29	375	7,970	m^3	33	28.61
		28	875	175,794	m^3	714	35.08
		27	1,000	180,453	m^3	884	35.1
		24	1,000	151,398	m^3	644	36.36
		31	465	360,651	m^3	1,488	36.45
		27	250	205,545	m^3	867	36.65
		35	175	22,604	m^3	93	33.96
		26	250	86,735	m^3	312	30.67
		27	250	311,135	m^3	1,400	38.57
		28	1,400	446,596	m^3	4,665	38.16
		32	950	421,797	m^3	5,741	37.84
		23	250	134,497	m^3	563	36.19
		38	306	295,363	m^3	1,900	36.31
		37	150	37,835	m^3	554	34.11
		33	844	55,920	m^3	5,746	39.75
(25%-40%)		29	506	104,537	m^3	3,107	35.97
High		31	613	34,883	m^3	3,528	40.74
(>40%)							
# boiler, gas turbine, simple cycle, combined cycle, cogeneration.		Totals	49,473	15,374,321	m^3	98,713	
Biomass							
Low							
(<25%)							
Moderate							
(25%-40%)							
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	-	-		-	
Hydroelectric							
Nuclear			45,082			316,498	
Other							
(describe)							
		Totals	-	-		-	
Total of listed energy sources			178,754	95,435,622		815,464	

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A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Base year for power capacity growth:

Describe Design (See # below for examples)	By 2005 Capacity Addition (MW)	By 2005 Efficiency (%)	By 2010 Capacity Addition (MW)	By 2010 Efficiency (%)	By 2020 Capacity Addition (MW)	By 2020 Efficiency (%)
Coal	39754		44132			
Oil	51502		51107			
Natural gas	58881		66958			
Biomass						
Hydroelectric	45684		48095			
Nuclear	59580		61854			
Other: (list)						
Total all Systems	215647		228014		0	

#		
	Coal	pulverized, fluidized, stoker, saturated, superheated, etc.
	Natural gas	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
	Oil	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
	Biomass	pulverized, fluidized, stoker, saturated, superheated, etc.

B) Stength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.

		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.			
	Availlability of skilled labour in your region (skilled operators, trades people)			
	Availability of professionals in your region (engineers, managers, financial)			
Operational	Adequacy and sophistication of maintenance program			
	Training level of operating, maintenance and management staff			

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Future Options to Reduce Green House Gas (GHG) Emissions from Existing Plants

Please check off one or more options to reduce national CO_2 emissions. For each option, separately report actual use from those of potential interest. Make your best estimates of the capacity being impacted, efficiencies for each option (if known) and other data in the

Options	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity (MW)	Current Efficiency (%)	New System: New Efficiency (%)	New System: CO_2 Reduction (ktonnes/yr.)	Types of technology- please state briefly See other worksheets for examples of technology descriptions. For cogeneration of thermal energy, indicate fuel type and efficiency gain.	State if (A)ctual or (P)otential
☐ **Option 1-** ***Replacement of old technology and small plants with better systems using the same fuel.***									
1	coal								
	oil								
	natural gas								
☐ **Option 2-** ***Retrofit technology for the same fuel type to improve combustion efficiency (e.g. instrumentation, new burner technology, reduced excess air, preheat air and/or water, etc.)***									
2	coal								
	oil								
	natural gas								
☐ **Option 3-** ***Increase efficiency by improving facility operation and maintenance with same equipment.***									
3	coal								
	oil								
	natural gas								
☐ **Option 4-** ***Convert to higher efficiency technology (e.g. from simple to combined cycle gas turbine, low to high pressure steam turbine, etc.)***									
4	coal								
	oil								
	natural gas								

☐ **Option 5-** ***Switch to lower carbon containing fuel using same technology (include thermal capacity for cogeneration)***

5	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity: Elect. (MW)	Capacity: Thermal (MW)	% Capacity Split According to Fuel Type: Oil	Natural gas	Biomass	Hydro	Nuclear	Other	State if (A)ctual or (P)otential
	coal											
	oil					-						
	natural gas					-	-					

☐ **Option 6-** ***Apply taxes, energy policies, emission trading or other approaches to reduce green house gas emissions.***

6	Fuel Type	Economic instruments such as taxes, incentives, emission trading, premiums for certain fuels, promotion of conversion, etc. Also, include other approaches. Please describe. Method to Promote Emission Reduction	Impacted Capacity (MW)	CO_2 Reduction (ktonnes/yr.)	State if (A)ctual or (P)otential

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Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design		Combined Data for Each Plant Group					
(Group by Efficiency and Design)		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low *(<25%)*							
Moderate *(25%-40%)*	Pulverized	8	13,031	18,089	1,000TOE	81,544	39
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	13031	18089		81544	
Natural Gas							
Low *(<25%)*							
Moderate *(25%-40%)*	Simple cycle	6	1,538	323	1,000TOE	1,345	38
High *(>40%)*	Combined cycle	5	10,935	5,900	1,000TOE	28,779	44
# boiler,gas turbine, simple cycle, combined cycle, cogeneration,		Totals	12473	6223		30124	43
Light & Heavy Fuel Oil							
Low *(<25%)*							
Moderate *(25%-40%)*	Simple cycle	14	4,611	3,268	1,000TOE	18,527	37
High *(>40%)*							
# boiler, gas turbine, simple cycle, combined cycle, cogeneration		Totals	4611	3268		18527	
Biomass							
Low *(<25%)*							
Moderate *(25%-40%)*							
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	0	0		0	
Hydroelectric		15	3,148	1,517	1,000TOE	6,066	36
Nuclear		9	13,716	25,766	1,000TOE	103,064	36
Other (describe)							
		Totals	0	0		0	
Total of listed energy sources			46979	54863	1,000TOE	239325	39

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A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Base year for power capacity growth: 1999

Describe Design (See # below for examples)	By 2005 Capacity Addition (MW)	By 2005 Efficiency (%)	By 2010 Capacity Addition (MW)	By 2010 Efficiency (%)	By 2020 Capacity Addition (MW)	By 2020 Efficiency (%)
Coal	n.a		8,269		8,689	
Oil	n.a		720		120	
Natural gas	n.a		5,077		7,327	
Biomass	n.a		n.a		n.a	
Hydroelectric	n.a		3,778		3,778	
Nuclear	n.a		9,713		13,934	
Other: (list)						
Total all Systems	0		27,558		33,849	

# Coal	pulverized, fluidized, stoker, saturated, superheated, etc.
Natural gas	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Oil	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Biomass	pulverized, fluidized, stoker, saturated, superheated, etc.

B) Stength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.

		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.		o	
	Availlability of skilled labour in your region (skilled operators, trades people)	o		
	Availability of professionals in your region (engineers, managers, financial)		o	
Operational	Adequacy and sophistication of maintenance program	o		
	Training level of operating, maintenance and management staff	o		

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Future Options to Reduce Green House Gas (GHG) Emissions from Existing Plants

Please check off one or more options to reduce national CO_2 emissions. For each option, separately report actual use from those of potential interest. Make your best estimates of the capacity being impacted, efficiencies for each option (if known) and other data in the

Options	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity (MW)	Current Efficiency (%)	New System: New Efficiency (%)	New System: CO_2 Reduction (ktonnes/yr.)	Types of technology- please state briefly. See other worksheets for examples of technology descriptions. For cogeneration of thermal energy, indicate fuel type and efficiency gain.	State if (A)ctual or (P)otential

☐ **Option 1-** ***Replacement of old technology and small plants with better systems using the same fuel.***

	Fuel Type	Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)	Types of technology	State if (A)ctual or (P)otential
1	coal								
	oil								
	natural gas								

☐ **Option 2-** ***Retrofit technology for the same fuel type to improve combustion efficiency (e.g. instrumentation, new burner technology, reduced excess air, preheat air and/or water, etc.)***

	Fuel Type	Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)	Types of technology	State if (A)ctual or (P)otential
2	coal								
	oil								
	natural gas								

☐ **Option 3-** ***Increase efficiency by improving facility operation and maintenance with same equipment.***

	Fuel Type	Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)	Types of technology	State if (A)ctual or (P)otential
3	coal								
	oil								
	natural gas								

☐ **Option 4-** ***Convert to higher efficiency technology (e.g. from simple to combined cycle gas turbine, low to high pressure steam turbine, etc.)***

	Fuel Type	Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)	Types of technology	State if (A)ctual or (P)otential
4	coal								
	oil								
	natural gas								

☐ **Option 5-** ***Switch to lower carbon containing fuel using same technology (include thermal capacity for cogeneration)***

5	Projected Capacity of Plants to be Affected: Fuel Type	Annual Fuel Use: Quantity	Annual Fuel Use: Units	Capacity: Elect. (MW)	Capacity: Thermal (MW)	% Capacity Split According to Fuel Type: Oil	Natural gas	Biomass	Hydro	Nuclear	Other	State if (A)ctual or (P)otential
	coal											
	oil					-						
	natural gas					-	-					

☐ **Option 6-** ***Apply taxes, energy policies, emission trading or other approaches to reduce green house gas emissions.***

6	Economic instruments such as taxes, incentives, emission trading, premiums for certain fuels, promotion of conversion, etc. Also, include other approaches. Please describe. Fuel Type	Method to Promote Emission Reduction	Impacted Capacity (MW)	CO_2 Reduction (ktonnes/yr.)	State if (A)ctual or (P)otential

Economy:	Hong Kong Special Administrative Region, PRC	Person:	Mr. S.W. Pang (Principal Environmental Protection Officer)	Email:	
Organization:	Environmental Protection Department	Tel:	(852) 2594-6300	Fax:	(852) 2827-8040

Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design	(Group by Efficiency and Design)	Combined Data for Each Plant Group					
		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low *(<25%)*							
Moderate *(25%-40%)*	Pulverized Coal Fired Boilers	3-19	6,608	6,866,299	Tonnes	19,644	36
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	6,608	6,866,299	Tonnes	19,644	
Natural Gas							
Low *(<25%)*							
Moderate *(25%-40%)*							
High *(>40%)*	combined cycle	3-6	1,872	2539539.4	$10^3 m^3$	11727.49	46.78
# boiler,gas turbine, simple cycle, combined cycle, cogeneration,		Totals	1,872	2539539.4	$10^3 m^3$	11727.49	
Light & Heavy Fuel Oil							
Low *(<25%)*	Oil Fired Gas Turbines-peak looping only	14-22	1,114	1,663.37	Tonnes	<4	18-30
Moderate *(25%-40%)*							
High *(>40%)*							
# boiler, gas turbine, simple cycle, combined cycle, cogeneration		Totals	1,114	1,663.37	Tonnes	<4	
Biomass							
Low *(<25%)*							
Moderate *(25%-40%)*							
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	0	0		0	
Hydroelectric							
Nuclear							
Other (describe)							
		Totals	0	0		0	
Total of listed energy sources			9,594		Tonnes	31,375	

Economy	Hong Kong Special Administrative Region, PRC	Person:	Mr. S.W. Pang (Principal Environmental Protection Officer)	Email:	
Organizati	Environmental Protection Department	Tel:	(852) 2594-6300	Fax:	(852) 2827-8040

A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.

Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Base year for power capacity growth: 2000

Describe Design (See # below for examples)	By 2005		By 2010		By 2020	
	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)
Coal						
Oil						
Two oil fired gas turbines will be converted to						
a gas fired combined cycle unit						
Natural gas						
Natural Gas Fired Combined Cycle Power						
Generation Units						
Gas fired combined cycle unit converted from						
two oil fired gas turbines						
Biomass						
Hydroelectric						
Nuclear						
Other: (list)						
Total all Systems	0		0		0	

#		
#	Coal	pulverized, fluidized, stoker, saturated, superheated, etc.
	Natural gas	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
	Oil	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
	Biomass	pulverized, fluidized, stoker, saturated, superheated, etc.

B) Stength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.			
	Availlability of skilled labour in your region (skilled operators, trades people)			
	Availability of professionals in your region (engineers, managers, financial)			
Operational	Adequacy and sophistication of maintenance program			
	Training level of operating, maintenance and management staff			

Economy: Hong Kong Special Administrative Region, PRC Person: Mr. S.W. Pang (Principal Environmental Protection Officer) Email:

Organization: Environmental Protection Tel: (852) 2594-6300 Fax: (852) 2827-8040

Future Options to Reduce Green House Gas (GHG) Emissions from Existing Plants

Please check off one or more options to reduce national CO_2 emissions. For each option, separately report actual use from those of potential interest. Make your best estimates of the capacity being impacted, efficiencies for each option (if known) and other data in the table below.

Options	Projected Capacity of Plants to be Affected					New System		Types of technology- please state briefly	State if
	Fuel Type	Annual Fuel Use		Capacity	Current Efficiency	New Efficiency	CO_2 Reduction	See other worksheets for examples of technology descriptions. For cogeneration of thermal energy, indicate fuel type and efficiency gain.	(A)ctual or (P)otential
		Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)		
☐ **Option 1-** ***Replacement of old technology and small plants with better systems using the same fuel.***									
1	coal								
	oil								
	natural gas								
☐ **Option 2-** ***Retrofit technology for the same fuel type to improve combustion efficiency (e.g. instrumentation, new burner technology, reduced excess air, preheat air and/or water, etc.)***									
2	coal								
	oil								
	natural gas								
☐ **Option 3-** ***Increase efficiency by improving facility operation and maintenance with same equipment.***									
3	coal								
	oil								
	natural gas								
☐ **Option 4-** ***Convert to higher efficiency technology (e.g. from simple to combined cycle gas turbine, low to high pressure steam turbine, etc.)***									
4	coal								
	oil								
	natural gas								

☐ **Option 5-** ***Switch to lower carbon containing fuel using same technology (include thermal capacity for cogeneration)***

	Projected Capacity of Plants to be Affected					% Capacity Split According to Fuel Type						State if
	Fuel Type	Annual Fuel Use		Capacity		Oil	Natural gas	Biomass	Hydro	Nuclear	Other	(A)ctual or
5		Quantity	Units	Elect. (MW)	Thermal (MW)							(P)otential
	coal											
	oil					-						
	natural gas					-	-					

☐ **Option 6-** ***Apply taxes, energy policies, emission trading or other approaches to reduce green house gas emissions.***

	Economic instruments such as taxes, incentives, emission trading, premiums for certain fuels, promotion of conversion, etc. Also, include other approaches. Please describe.		Impacted Capacity	CO_2 Reduction	State if (A)ctual or
6	Fuel Type	Method to Promote Emission Reduction	(MW)	(ktonnes/yr.)	(P)otential

Economy: PHILLIPINES Person: Email:
Organization: Tel: Fax:

Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design (Group by Efficiency and Design)		Combined Data for Each Plant Group					
		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low							
(<25%)							
Moderate	PC Plant	19	50	19,406	tonnes	39.00	28%
(25%-40%)	PC Plant	14	55	78,237	tonnes	155.00	28%
	PC Plant	16	300	535,197	tonnes	1,285.00	34%
	PC Plant	5	300	670,843	tonnes	1,285.00	31%
	PC Plant, 2X300	2	600	1,123,645	tonnes	3,070.00	34%
High							
(>40%)							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	1,305	2,427,327.34		5,834.00	
Natural Gas							
Low							
(<25%)							
Moderate							
(25%-40%)							
High							
(>40%)							
# boiler,gas turbine, simple cycle, combined cycle, cogeneration, etc.		Totals	0	0		0	
Light & Heavy Fuel Oil							
Low							
(<25%)	Gas Turbine	9	55	1,150	m^3	3.00	18%
Moderate	Thermal, Once-through	31	300	183,819	m^3	656.00	29%
(25%-40%)	Thermal, Once-through	31	150	86,321	m^3	328.00	31%
	Thermal, Once-through	31	200	109,057	m^3	437.00	31%
	Thermal, Drum-type	25	300	137,374	m^3	559.00	33%
	Thermal, Once-through	21	350	155,406	m^3	652.00	34%
	Diesel Plant	20	44	2,267	m^3	9.00	33%
	Gas Turbine	12	90	543	m^3	2.00	28%
	Gas Turbine	12	120	1,912	m^3	8.00	28%
	Gas Turbine	8	30	963	m^3	4.00	29%
	Diesel Plant	23	37	648	m^3	25.00	36%
	Diesel Plant	23	11	455	m^3	18.00	36%
	Diesel Plant	23	9	372	m^3	15.00	36%
	Diesel Plant	9	32	2,209	m^3	86.00	36%
	Diesel Plant	9	32	416	m^3	16.00	36%
	Diesel Plant	9	32	488	m^3	19.00	36%
	Diesel Plant	9	32	272	m^3	11.00	36%

High (>40%)	Diesel Plant	7	100	130,615	m^3	701.00	44%
	Combined Cycle	7	420	95,529	m^3	516.00	44%
	Combined Cycle	6	200	45,500	m^3	246.00	44%
	Diesel Plant	6	100	129,033	m^3	701.00	44%
# boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.		Totals	2,643	1,084,351		5,012	
Biomass							
Low (<25%)							
Moderate (25%-40%)							
High (>40%)							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	0	0.00		0.00	
Hydroelectric							
	Pump Storage	18	300			432.00	
	Conventional	40	100			307.00	
	Conventional	32	200			597.00	
	Conventional	23	100			194.00	
	Conventional	22	46			138.00	
	Conventional	20	12			48.00	
	Conventional	16	360			1,405.00	
	Conventional	43	2			13.00	
	Conventional	23	150			752.00	
	Conventional	47	50			251.00	
	Conventional	21	180			675.00	
	Conventional	17	54			282.00	
	Conventional	15	55			287.00	
	Conventional	15	158			810.00	
	Conventional	7	80			14.00	
Nuclear							
Other	Binary	6	15	24,971	Tonnes	46.00	14%
Geothermal (steam)	Conventional, Pilot Plant	17	3	11,033	Tonnes	20.00	14%
	Conventional	17	113	413,730	Tonnes	760.00	14%
	Conventional	5	80	330,569	Tonnes	607.00	14%
	Conventional	17	113	413,730	Tonnes	760.00	14%
	Conventional	19	330	803,612	Tonnes	1,476.00	14%
	Conventional	19	330	1,105,637	Tonnes	2,031.00	14%
	Conventional	5	80	268,033	Tonnes	492.00	14%
	Conventional	5	110	247,324	Tonnes	454.00	14%
	Conventional	3	110	89,935	Tonnes	165.00	14%
		Totals	1,283	3,708,574		6,811.00	
Total of listed energy sources			5,231	7,220,253.04		17,657.00	

Note:Only NPC Owned Power Plants, IPP's are not included

Economy: PHILLIPINES | Person: | Email:
Organization: | Tel: | Fax:

A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.
Base year for power capacity growth:

Describe Design (See # below for examples)	By 2005		By 2010 [1]		By 2020	
	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)
Coal						
Pulverized Coal	460	35%				
Pulverized Coal			200	38%		
Generic Coal Plant			250	38%		
Oil						
Diesel Plant	1040	49%				
Diesel Plant	525	51%				
GT Plants, 6x30	180	25%				
Generic Diesel Plant	130	38%	160	38%		
GT Plants, 5x30, 1x50			200	25%		
Natural gas						
Combined Cycle	1200	56%	0			
Combined Cycle	300	54%				
Biomass						
Agricultural Waste, Stoker	40	33%				
Hydroelectric						
Pump Station	350					
Conventional, 1x70, 1x140, 1x345	555					
Conventional, 2x225, 1x68			518			
Nuclear						
Other: (list)						
BaseLoad Plant*			1800			
Peaking Plant*			450			
Geothermal			40			
Various NRE's from Provinces	16					
Total all Systems	4796		3618		0	

Coal — pulverized, fluidized, stoker, saturated, superheated, etc.
Natural gas — boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Oil — boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Biomass — pulverized, fluidized, stoker, saturated, superheated, etc.

[1] Data available Only until 2009
N.A. Not available

B) Stength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.

		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.			*
	Availlability of skilled labour in your region (skilled operators, trades people)	*		
	Availability of professionals in your region (engineers, managers, financial)	*		
Operational	Adequacy and sophistication of maintenance program	*		
	Training level of operating, maintenance and management staff	*		

*Generic Plants whose kind of technology is not yet identified.
** Our planning scenario is only for 10 years.

Economy: Peru	**Person:** Eco. Iris Cardenas	**Email:** icardena@mem.gob.pe	
Organization: Ministry of Energy and Mines	**Tel:** 51-1-4750331	**Fax:** 51-1-4750331	

Profile of Existing Electricity Generation Facilities in 2000

Report data for groups of plants having the same fuel and similar power plant technology. Make a reasonable estimate using available data. Data is needed for any two of the columns headed fuel use; annual power; and plant efficiency.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Plant Fuel and Design (Group by Efficiency and Design)		Combined Data for Each Plant Group					
		Plant Age	Electricity Capacity	Annual Fuel Use		Annual Power	Typical Efficiency
Fuel; Efficiency	Describe (see # below for examples)	years	MW	Quantity	Units	GWh	%
Coal							
Low *(<25%)*							
Moderate *(25%-40%)*							
High *(>40%)*	Steam Turbine	8 month	135.0	123,448	Tonnes	363.6	40.6
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	135.0	123448.1	Tonnes	363.6	
Natural Gas							
Low *(<25%)*	Natural Gas Engine			915.1	$10^3\ m^3$	8.1	22.1
	Gas Turbine			22008.6	$10^3\ m^3$	39.2	17.9
Moderate *(25%-40%)*	Natural Gas Engine			30121.3	$10^3\ m^3$	399.9	30.8
	Gas Turbine			222908.8	$10^3\ m^3$	629.6	27.4
High *(>40%)*	Natural Gas Engine			252.4	$10^3\ m^3$	6.3	41.6
	Gas Turbine						
# boiler,gas turbine, simple cycle, combined cycle, cogeneration,		Totals	333.3	276206.3	$10^3\ m^3$	1083.1	
Light & Heavy Fuel Oil							
Low *(<25%)*	Diesel Engine			1752.0	m^3	3.8	21.2
	Gas Turbine			1704.3	m^3	4.2	22.3
	Steam Turbine			2173.4	m^3	4.2	20.4
Moderate (25%-40%)	Combined Cycle		21.0	580.9	m^3	2.2	37.4
	Diesel Engine			265983.8	m^3	746.0	31.5
	Gas Turbine			28635.8	m^3	76.8	28.2
	Steam Turbine			180603.7	m^3	834.7	28.2
High *(>40%)*	Diesel Engine			4854.7	m^3	18.8	42.1
	Steam Turbine			5560.4	m^3	30.3	42.2
# boiler, gas turbine, simple cycle, combined cycle, cogeneration		Totals	2716.1	491849.0	m^3	1720.9	
Biomass							
Low *(<25%)*	Steam Turbine (Bagasse)		25.2	136513.3	Tonnes	54.7	20.8
Moderate *(25%-40%)*							
High *(>40%)*							
# pulverized, fluidized, stoker, saturated, superheated, etc.		Totals	25.2	136513.3	Tonnes	54.7	
Hydroelectric			2859.5			16128.0	80.0
Nuclear							
Other (describe)							
		Totals	0.0			0.0	
Total of listed energy sources			6069.1			19350.2	

Source: Electricity General Directorate
Elaborated: Energy Technical Office

Economy: Peru | **Person:** Eco. Iris Cardenas | **Email:** icardena@mem.gob.pe

Organization: Ministry of Energy and Mines | **Tel:** 51-1-4750331 | **Fax:** 51-1-4750331

A) Future Additional Electricity Generation

Please provide planned additions to system capacity relative to base year . Make a reasonable estimate using available data. Combined data for groups of facilities that will use the same fuel and similar technology.
Plant efficiency = (Net Electricity+ Used Thermal Energy)/(Input Lower Heating Value of Fuel), as percent.

Base year for power capacity growth:

Describe Design (See # below for examples)	By 2005		By 2010		By 2015	
	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)	Capacity Addition (MW)	Efficiency (%)
Coal						
Steam Turbine	135	35				
Oil						
Natural gas						
Combined Cycle			992	55	496	55
Gas Turbine	516	37	172	37	516	37
Biomass						
Hydroelectric						
	335	80				
Nuclear						
Other: (list)						
Total all Systems	986		1164		1012	

#	
Coal	pulverized, fluidized, stoker, saturated, superheated, etc.
Natural gas	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Oil	boiler, gas turbine, simple cycle, combined cycle, cogeneration, etc.
Biomass	pulverized, fluidized, stoker, saturated, superheated, etc.

B) Strength and Weaknesses Assessment:

Check only one box as it applies in your opinion to your plant or system.		Strength	Neutral	Weakness
Financial	Availability of capital for upgrades which are economically attractive.	x		
	Availlability of skilled labour in your region (skilled operators, trades people)	x		
	Availability of professionals in your region (engineers, managers, financial)	x		
Operational	Adequacy and sophistication of maintenance program (1)	x		
	Training level of operating, maintenance and management staff	x		

(1) It is strength at the enterprises level, but in the system's operation there isn't enough coordination
Source: Electricity General Directorate
Elaborated: Energy Technical Office

Economy: Peru | Person: Eco. Iris Cardenas | Email: icardena@mem.gob.pe
Organization: Ministry of Energy and Mines | Tel: 51-1-4750331 | Fax: 51-1-4750331

Future Options to Reduce Green House Gas (GHG) Emissions from Existing Plants

Please check off one or more options to reduce national CO_2 emissions. For each option, separately report actual use from those of potential interest. Make your best estimates of the capacity being impacted, efficiencies for each option (if known) and other data in the

Options	Projected Capacity of Plants to be Affected					New System		Types of technology- please state briefly	State if
	Fuel Type	Annual Fuel Use		Capacity	Current Efficiency	New Efficiency	CO_2 Reduction	See other worksheets for examples of technology descriptions. For cogeneration of thermal energy, indicate fuel type and efficiency gain.	(A)ctual or (P)otential
		Quantity	Units	(MW)	(%)	(%)	(ktonnes/yr.)		
☐ **Option 1-** ***Replacement of old technology and small plants with better systems using the same fuel.***									
1	coal								
	oil								
	natural gas								
☐ **Option 2-** ***Retrofit technology for the same fuel type to improve combustion efficiency (e.g. instrumentation, new burner technology, reduced excess air, preheat air and/or water, etc.)***									
2	coal								
	oil								
	natural gas								
☐ **Option 3-** ***Increase efficiency by improving facility operation and maintenance with same equipment.***									
3	coal								
	oil								
	natural gas								
☐ **Option 4-** ***Convert to higher efficiency technology (e.g. from simple to combined cycle gas turbine, low to high pressure steam turbine, etc.)***									
4	coal								
	oil								
	natural gas								

☐ **Option 5-** ***Switch to lower carbon containing fuel using same technology (include thermal capacity for cogeneration)***

5	Projected Capacity of Plants to be Affected					% Capacity Split According to Fuel Type						State if
	Fuel Type	Annual Fuel Use		Capacity		Oil	Natural gas	Biomass	Hydro	Nuclear	Other	(A)ctual or (P)otential
		Quantity	Units	Elect. (MW)	Thermal (MW)							
	coal											
	oil					-						
	natural gas					-	-					

☐ **Option 6-** ***Apply taxes, energy policies, emission trading or other approaches to reduce green house gas emissions.***

6	Economic instruments such as taxes, incentives, emission trading, premiums for certain fuels, promotion of conversion, etc. Also, include other approaches. Please describe.		Impacted Capacity	CO_2 Reduction	State if
	Fuel Type	Method to Promote Emission Reduction	(MW)	(ktonnes/yr.)	(A)ctual or (P)otential

Note: The information is unavailable

Appendix D Indicative Options for Reducing Greenhouse Gas Emissions from Existing Plants

The Australian Greenhouse Office prepared Technical Guidelines for the Electricity Generator Standards that have been implemented in Australia. The following tables have been extracted from Appendix C of version 1.2 of the Technical Guidelines for ease of reference in this study, as they provide a useful list of potential power plant efficiency improvements. The information is based on a number of studies of options for reducing the carbon dioxide emissions, and improving the efficiency, of power plants in Australia. The full guideline may be downloaded from www.greenhouse.gov.au/pubs.

Table D- 1 Options for Greenhouse Gas Reduction: Boiler, Steam Turbine and Heat Recovery Steam Generator

Action	*Description*	*Potential Efficiency Improvement, % HHV*
Restore the Plant to Design Condition		
Operate boiler at the design O_2 in flue gas	Any O_2 in the flue gas represents an excess of air above that needed for combustion and is a loss of energy to the because that excess air leaves the boiler at a higher temperature than it entered. Reduced excess air will bring an immediate increase in boiler efficiency.	Up to 0.6
Restore and maintain air-heaters	The air-heater plays an important part in recovering energy from the combustion products. If the air-heater is allowed to operate with ash deposits or with damaged or missing surface (in the case of rotary air-heaters), boiler efficiency will be reduced.	Up to 0.3
Minimise boiler tramp air	Boiler tramp air does not pass through the air-heater, which means that the reduced air flow through the air-heater will not cool the flue gas as much as intended resulting in lower efficiency. It also forces operation with higher than necessary excess air.	Up to 1.0
Reinstate any feed-heaters out of service	Feed-heaters improve steam cycle efficiency by using low-grade heat from low-pressure steam from the turbine to heat the boiler feed water. Feed-heaters are sometimes taken out of service permanently to overcome steam leakage problems. This can lead to an increase in power output, but at reduced fuel efficiency. The effect on efficiency is different depending on the plant design.	Up to 2.0

Table D-1 Options for Greenhouse Gas Reduction: Boiler, Steam Turbine and Heat Recovery Steam Generator (continued)

Action	*Description*	*Potential Efficiency Improvement, % HHV*
Reduce turbine gland leakage	The main gland leakage point is between the high pressure cylinder and the intermediate pressure cylinder. Any leakage of steam at this point allows it to bypass the high pressure turbine without any useful work being done by it.	Up to 0.2
Change Operational Settings		
Low excess air operation	Low excess air operation reduces the quantity of combustion gases and, hence, the heat loss from the dry flue gases leaving the boiler. The excess air level is a trade-off between unburnt fuel loss at low excess air and flue gas loss at high excess air. The level can often be reduced, particularly if the combustion system is properly tuned and controlled.	Up to 1.2
Improved combustion control	Improved combustion control enables the boiler to operate with lower excess air without the risk of combustion instability or excessive unburnt fuel. It involves both burner tuning better control system performance to keep the plant in a safe condition with low excess air.	Up to 0.5
Increased condenser cleaning	Condenser fouling causes the turbine back pressure to increase. More frequent cleaning can keep this increase to a minimum, allowing higher efficiency. The cleaning can either be on-line or off-line. The rate of condenser fouling depends on many factors. The improvement that is possible is plant specific.	Up to 0.5
Increased boiler cleaning	Boiler ash deposits reduce heat transfer rates and ultimately lead to higher flue gas temperatures. The boiler can be kept cleaner, either through off-load cleaning or through the use of better on-load cleaning systems such as soot blowers, water blowers and water cannons.	Up to 1.0
Retrofit Improvements		
Add extra heat transfer surface in the boiler, eg. economiser or air-heater	Extra heat transfer surface in the boiler will enable additional heat to be extracted from the flue gas leading to lower flue gas temperatures. In some cases, the boilers already have space allowance for extra air-heater surface. There is an increased risk of low temperature corrosion.	Up to 0.8
Install additional sootblowers	Additional sootblowers will help keep the boiler surfaces cleaner and, thus, increase the effective surface area. This will bring a slight reduction in flue gas temperature.	Up to 0.4
Install new high efficiency turbine blades	Modern turbine blades have 3-dimensional variation in shape and are more efficient than the original blades. It is possible to install new blades in the last rows or replace all blades and install new rotors.	Up to 1.0

Table D-1 Options for Greenhouse Gas Reduction: Boiler, Steam Turbine and Heat Recovery Steam Generator (continued)

Action	*Description*	*Potential Efficiency Improvement, % HHV*
Change to steam driven feed pumps	Steam driven feed pumps can reduce the auxiliary power requirements of the plant by using lower grade energy for feed pumping.	
Install variable speed drives on major plant items	Variable speed drives allow the auxiliary power consumption to be reduced as the plant load is reduced, and thus the benefits plants that have long periods of operation at reduced load.	Up to 0.4
Install on-line condenser cleaning system	Improved condenser cleaning can improve efficiency by allowing lower turbine exhaust temperatures. On-line cleaning will allow the condenser to be kept at a high level of cleanliness.	Up to 0.5
Install new cooling tower film pack	In plants that use cooling towers, installing new film-type packs can reduce the cooling water temperature to the condensers. Some cooling towers only have spray systems, which are less effective.	Up to 1.0

Table D- 2 Greenhouse Emission Reduction: Open-Cycle Gas Turbine Plant

Action	*Description*	*Potential Efficiency Improvement, % HHV*
Restore the Plant to Design Condition		
Replace/clean fouled air filters	Fouled air filters increase the pressure drop across the air inlet to the gas turbine compressor.	Up to 0.4%
Change Operational Settings		
Increase frequency of compressor cleaning	Compressor washing restores compressor efficiency.	Up to 0.5% per wash
Check control system settings	Check IGV angles, instrument calibration and hardware for correct operation.	Up to 0.5%
Retrofit Improvements		
Consider inlet air conditioning	Options are chiller, evaporative cooler, mist/fog system.	Up to 1%
Upgrade components to increase firing temperature	Increased firing temperature increases efficiency.	Application specific
Review air inlet and GT exhaust arrangements	Revised inlet and exhaust duct arrangements may reduce pressure drop.	Up to 0.3%

Appendix E CO_2 Emission Calculation Summary

Table E-1 Detailed Summary Table for Calculation of CO_2 Emission Reductions for Each Scenario

Scenario ID	Scenario Description	Fossil Fuels	Applicable Technology Categories	1998 CO_2 Emissions (Mt CO_2)	Existing Capacity of Applicable Technology (MW)	Scenario Application to Percentage	Number of Plants for Scenario Application	Capacity of Plants for Scenario Application (MW)	CO_2 Emissions from Plants for Scenario Application (Mt CO_2)	Net Efficiency of Existing Plants (η_1)	Net Efficiency of Upgraded Plant (η_2)	CO_2 Reduction Due to Efficiency Improvement (Mt CO_2)	CO_2 Reduction Due to Fuel Switch (Mt CO_2)	Total CO_2 Reduction (Mt CO_2)	CO_2 Reduction for Plants included in Scenario Application	Cost Category (Low, Med, High)
E1	Combustion, Steam Cycle, O&M Improvements	Oil,Gas	ST Sub	770	289,149	50.0%	1,089	144,574	385	34%	36.5%	26	0	26	7%	Low-Med
E2	Combustion, Steam Cycle, O&M Improvements	Oil,Gas	GTCC & CHP	294	110,846	50.0%	2,852	55,423	147	50%	52.0%	6	0	6	4%	Low-Med
E3	Combustion, Steam Cycle, O&M Improvements	Oil,Gas	SC	96	119,062	50.0%	4,986	59,531	48	26%	31.0%	8	0	8	16%	Low-Med
E4	Combustion, Steam Cycle, O&M Improvements	Coal	PC Sub, PC Super	3,541	610,409	50.0%	1,375	305,204	1,770	34%	37.5%	165	0	165	9%	Low-Med
E5	Combustion, Steam Cycle, O&M Improvements	Coal	Stk/Cyc	118	33,653	50.0%	222	16,826	59	30%	33.5%	6	0	6	10%	Low-Med
E6	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Oil	ST Sub	344	125,116	28.7%	147	35,908	99	no change in efficiency	no change in efficiency	0	6	6	6%	Med
E7	Co-fire Boiler with 25% Gas: apply to all existing plants with gas capability	Coal	PC Sub	2,909	492,920	6.1%	189	30,068	177	no change in efficiency	no change in efficiency	0	19	19	11%	Med
E8	Co-fire Boiler with 25% Oil: apply to all existing plants with oil capability	Coal	PC Sub	2,909	492,920	8.2%	295	40,419	239	no change in efficiency	no change in efficiency	0	15	15	6%	Med
E9	Fuel Switch to Gas: apply to all existing plants with gas capability	Oil	ST Sub	344	125,116	28.7%	147	35,908	99	no change in efficiency	no change in efficiency	0	18	18	18%	Med-High
E10	Fuel Switch to Gas: apply to all existing plants with gas capability	Coal	PC Sub	2,909	492,920	6.1%	189	30,068	177	no change in efficiency	no change in efficiency	0	77	77	43%	Med-High
E11	Fuel Switch to Oil: apply to all existing plants with oil capability	Coal	PC Sub	2,909	492,920	8.2%	295	40,419	239	no change in efficiency	no change in efficiency	0	60	60	25%	Med-High

Table E-1 Detailed Summary Table for Calculation of CO_2 Emission Reductions for Each Scenario (Continued)

Scenario ID	Scenario Description	Fossil Fuels	Applicable Technology Categories	1998 CO_2 Emissions (Mt CO_2)	Existing Capacity of Applicable Technology (MW)	Scenario Application to Percentage	Number of Plants for Scenario Application	Capacity of Plants for Scenario Application (MW)	CO_2 Emissions from Plants for Scenario Application (Mt CO_2)	Net Efficiency of Existing Plants (η_1)	Net Efficiency of Upgraded Plant (η_2)	CO_2 Reduction Due to Efficiency Improvement (Mt CO_2)	CO_2 Reduction Due to Fuel Switch (Mt CO_2)	Total CO_2 Reduction (Mt CO_2)	CO_2 Reduction for Plants included in Scenario Application	Cost Category (Low, Med, High)
E12	Repower with GTCC	Oil,Gas	ST Sub	770	289,149	20.0%	varies based on size	57,830	154	34%	55%	59	0	59	38%	High (but less than new plant)
E13	Repower with GTCC	Oil,Gas	SC	96	119,062	40.0%	varies based on size	47,625	38	26%	55%	20	0	20	53%	High (but less than new plant)
E14	Repower with PC Super	Coal	PC Sub	2,909	492,920	10.0%	varies based on size	49,292	291	33%	42%	62	0	62	21%	High (but less than new plant)
E15	Repower with AFBC and 20% Biomass	Coal	PC Sub, Stk/Cyc	3,026	526,573	10.0%	varies based on size	52,657	303	33%	38%	40	30	70	23%	High (but less than new plant)
E16	Repower with AFBC and 100% Biomass	Coal	PC Sub, Stk/Cyc	3,026	526,573	5.0%	varies based on size	26,329	151	33%	38%	0	151	151	100%	High (but less than new plant)
E17	Repower with IGCC or PFBCC	Coal	PC Sub, Stk/Cyc	3,026	526,573	5.0%	varies based on size	26,329	151	33%	45%	40	0	40	27%	High (but less than new plant)
E18	Repower with CHP	Oil,Gas	ST Sub	770	289,149	5.0%	varies based on size	14,457	38	49%	75%	13	0	13	34%	High (but less than new plant)
E19	Repower with CHP	Coal	PC Sub	2,909	492,920	5.0%	varies based on size	24,646	145	49%	75%	50	0	50	34%	High (but less than new plant)